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LNG Worldwide — Facilities, Construction Projects, Statistics
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Refinery	E1340	E1340C
Pipeline	E1342	E1342C
Petrochemical	E1341	E1341C
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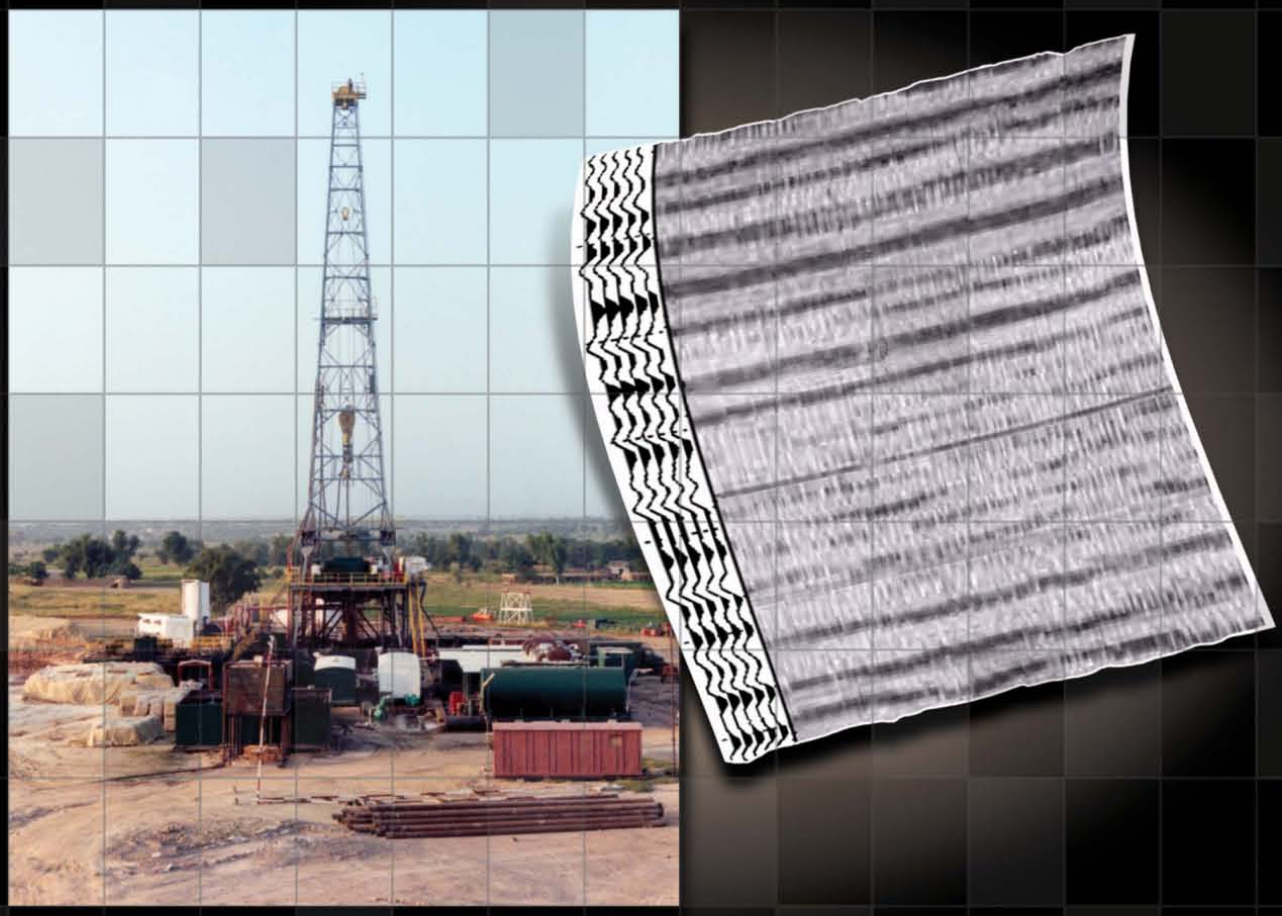


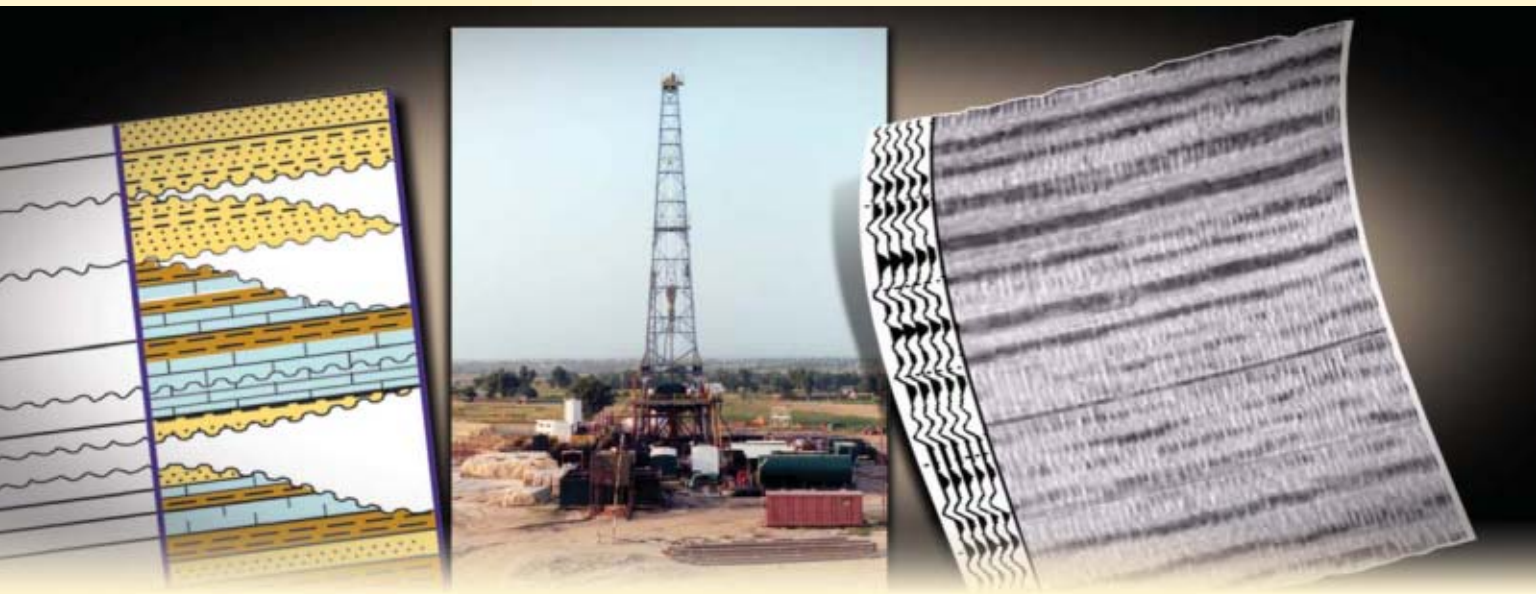
New Views of the Subsurface

Alaskan tax reform: Gas raises questions
Project undertakes production measurement gaps
Downturn will narrow 2009-10 margins for Asia-Pacific
Corrosion prompts integrity management changes

OIL&GAS JOURNAL®

June 1, 2009
Volume 107.21

NEW VIEWS OF THE SUBSURFACE



REGULAR FEATURES

COVER

A rig drills for gas-condensate for Oil & Gas Development Corp. Ltd. in Qadirpur field of Pakistan's Central Indus basin, where the Lower Eocene Sui Main limestone is the main pay zone. OGJ's New Views of the Subsurface special report features an article about how seismic sonic drift data and well data were used to predict overpressure before drilling at Qadirpur. The article starts on p. 36. Photo courtesy of Dr. Gulraiz Akhter, Quaid-i-Azam University.

General Interest

Exploration & Development

Drilling & Production

Processing

Transportation

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General Interest — Quick Takes

Pemex seeks larger budget to offset exchange rate

Mexico's state-owned Petroleos Mexicanos (Pemex) is negotiating with the government to increase its exploration budget by 20 billion pesos ($1.53 billion) due to the 30% decline of the peso against the US dollar.

"Pemex has an important part of its expenses in dollars—the exchange rate slide that we have seen means that our original budget has distortions," said Pemex exploration director Carlos Morales Gil.

The requested funds would account for about 20% of Pemex's exploration budget, said Morales Gil, who expressed optimism the government would grant the additional funds, which he considers essential for the company.

Morales Gil, who noted Pemex's initial 2009 spending plan projected an exchange rate level of 11.7 pesos per dollar compared with the current 13.1 pesos per dollar, said the state firm is working with the ministry of finance to clarify the situation.

"We believe we are going to manage this in the next few weeks or days even, so we can have a budget set to the exchange rate that is going to be in effect all year," he said.

Meanwhile he said Pemex estimates Mexico has 53 billion bbl of potential reserves, most of it offshore in the Gulf of Mexico. "That's where 80% of what we have to look for is. We clearly know where we have to do it," said Morales Gil.

"These discoveries [in the gulf] were made at a time when we need to replace reserves and try to sustain the level of production," he said, noting that production in January-April 2009 was 2.66 million b/d or 6.89% lower than in the same period last year.

Nonetheless, he said Pemex this year expects to add 1.05 billion bbl to its reserves, which total more than 14 billion bbl of crude. Last year, he said, the state firm added 1.4 billion bbl to its reserves.

In May, Pemex inaugurated its new board of directors, adding four newly created positions and raising the number of its members to 15 in line with national oil policy reforms enacted last year (OGJ Online, May 19, 2009).

Arkansas high court allows oil, gas lawsuit

The Arkansas Supreme Court agreed that legal questions exist regarding what authority state environmental regulators have over activities associated with oil and gas drilling in the Fayetteville shale.

The state's high court on May 21 rejected a request by the Arkansas Department of Environmental Quality to throw out a lawsuit that a plaintiffs' group of Arkansas producers filed against ADEQ in Union County, Ark.

The lawsuit is an attempt to stop ADEQ from issuing two types of general permits. Oil producers claim the Arkansas Oil & Gas Commission and the Arkansas Pollution Control & Ecology Commission have regulatory authority over oil and gas activities.

The general permits involve construction of pits at drillsites and for disposal of wastewater from drilling. Supreme Court Justice Robert L. Brown said it remains unclear whether the ADEQ went beyond its powers.

"Whether [those suing] will prevail on this claim remains to be seen," Brown said. "In any case, it is clear to this court that the issue of ADEQ's legal authority to act as it did needs further development before the circuit courts."

No future hearing dates have been set in Union County Circuit court, an ADEQ spokesman told OGJ. The circuit court previously rejected ADEQ's request to throw out the lawsuit.

Arkansas Gov. Mike Beebe has said he wants ADEQ to monitor drilling in the Fayetteville shale. A spokesman for the governor's office said it's too early to tell what effect the lawsuit might have on ADEQ.

Massachusetts approves offshore wind farm

A Massachusetts state agency granted the state and local permits needed for Cape Wind Associates LLC to construct a wind farm off Massachusetts in Nantucket Sound.

The Massachusetts Energy Facilities Siting Board on May 21 voted 7-0 to grant Cape Wind a certificate of environmental impact and public interest that combines all state and local permits.

Cape Wind Pres. Jim Gordon of Boston said the vote ends a 7-year state regulatory review of the project, which still needs federal authorization to proceed. The $1 billion project involves 130 wind turbines over 24 sq miles in Nantucket Sound within sight of Cape Cod residences.

The project awaits final approval by US Interior Secretary Ken Salazar. The Interior Department has issued guidelines for leasing offshore areas for renewable energy production, opening the door for wind farms.

The US Minerals Management Service issued Cape Wind a favorable final environmental impact statement in January. ✦

Exploration & Development — Quick Takes

BP group has deepwater find off Angola

A group led by BP PLC reported a discovery at Oberon, the 30th discovery on Blocks 31 and 32 off Angola, capable of flowing more than 5,000 b/d of oil.

The well, drilled to 12,300 ft measured depth in 5,300 ft of water 250 miles offshore on Block 31, cut oil-bearing reservoirs in

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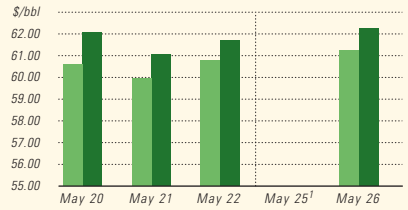
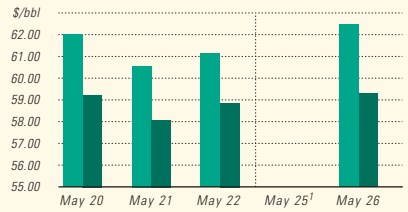
Industry Scoreboard

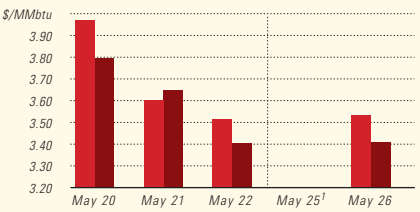
IPE BRENT / NYMEX LIGHT SWEET CRUDE



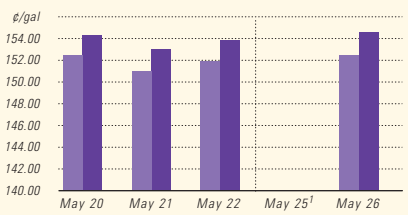
WTI CUSHING / BRENT SPOT



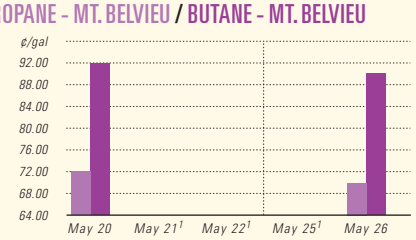
NYMEX NATURAL GAS / SPOT GAS - HENRY HUB



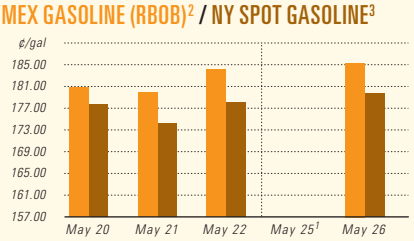
IPE GAS OIL / NYMEX HEATING OIL



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.

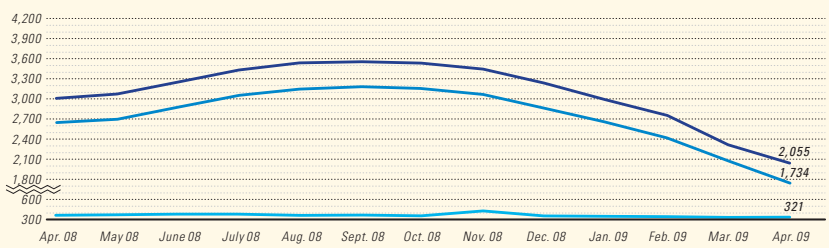
US INDUSTRY SCOREBOARD — 6/1

Latest week 5/15	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	9,054	9,167	–1.2	8,915	8,988	–0.8
Distillate	3,538	4,022	–12.0	3,821	4,151	–7.9
Jet fuel	1,436	1,578	–9.0	1,408	1,553	–9.3
Residual	456	673	–32.2	548	625	–12.3
Other products	3,771	4,309	–12.5	4,003	4,521	–11.5
TOTAL DEMAND	18,255	19,749	–7.6	18,695	19,838	–5.8
Supply, 1,000 b/d						
Crude production	5,302	5,164	2.7	5,316	5,131	3.6
NGL production[2]	1,835	2,313	–20.7	1,814	2,207	–17.8
Crude imports	9,311	9,764	–4.6	9,450	9,759	–3.2
Product imports	2,590	3,267	–20.7	3,004	3,191	–5.9
Other supply[3]	1,631	1,356	20.3	1,647	1,415	16.4
TOTAL SUPPLY	20,669	21,864	–5.5	21,231	21,703	–2.2
Refining, 1,000 b/d						
Crude runs to stills	14,264	15,114	–5.6	14,264	14,777	–3.5
Input to crude stills	14,597	15,410	–5.3	14,597	15,092	–3.3
% utilization	82.8	87.6	—	82.8	85.8	—

Latest week 5/15	Latest week	Previous week[1]	Change	Same week year ago[1]	Change	Change, %
Stocks, 1,000 bbl						
Crude oil	368,524	370,629	–2,105	320,442	48,082	15.0
Motor gasoline	203,954	208,291	–4,337	209,413	–5,459	–2.6
Distillate	148,127	147,455	672	107,790	40,337	37.4
Jet fuel-kerosine	39,665	40,126	–461	40,122	–457	–1.1
Residual	36,961	36,680	281	40,930	–3,969	–9.7
Stock cover (days)[4]			Change, %		Change, %	
Crude	25.6	25.5	0.4	21.5	19.1	
Motor gasoline	22.5	23.1	–2.6	22.5	0.0	
Distillate	41.9	42.2	–0.7	25.9	61.8	
Propane	58.5	54.0	8.3	36.5	60.3	
Futures prices[5] **5/22**			**Change**		**Change**	**%**
Light sweet crude ($/bbl)	60.69	58.07	2.62	124.93	–64.24	–51.4
Natural gas, $/MMbtu	3.83	4.30	–0.47	11.36	–7.54	–66.3

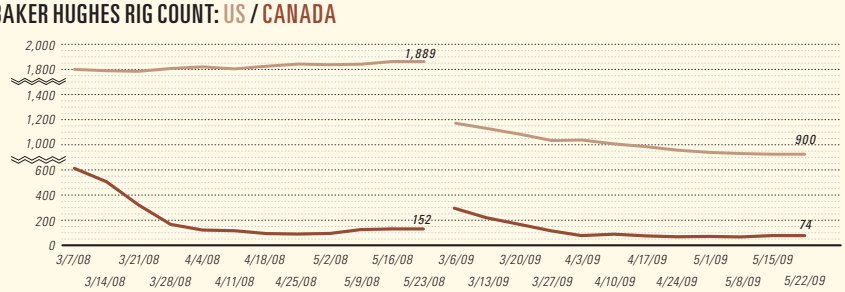
[1]Based on revised figures. [2]Includes adjustments for fuel ethanol and motor gasoline blending components. [3]Includes other hydrocarbons and alcohol, refinery processing gain, and unaccounted for crude oil. [4]Stocks divided by average daily product supplied for the prior 4 weeks. [5]Weekly average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

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

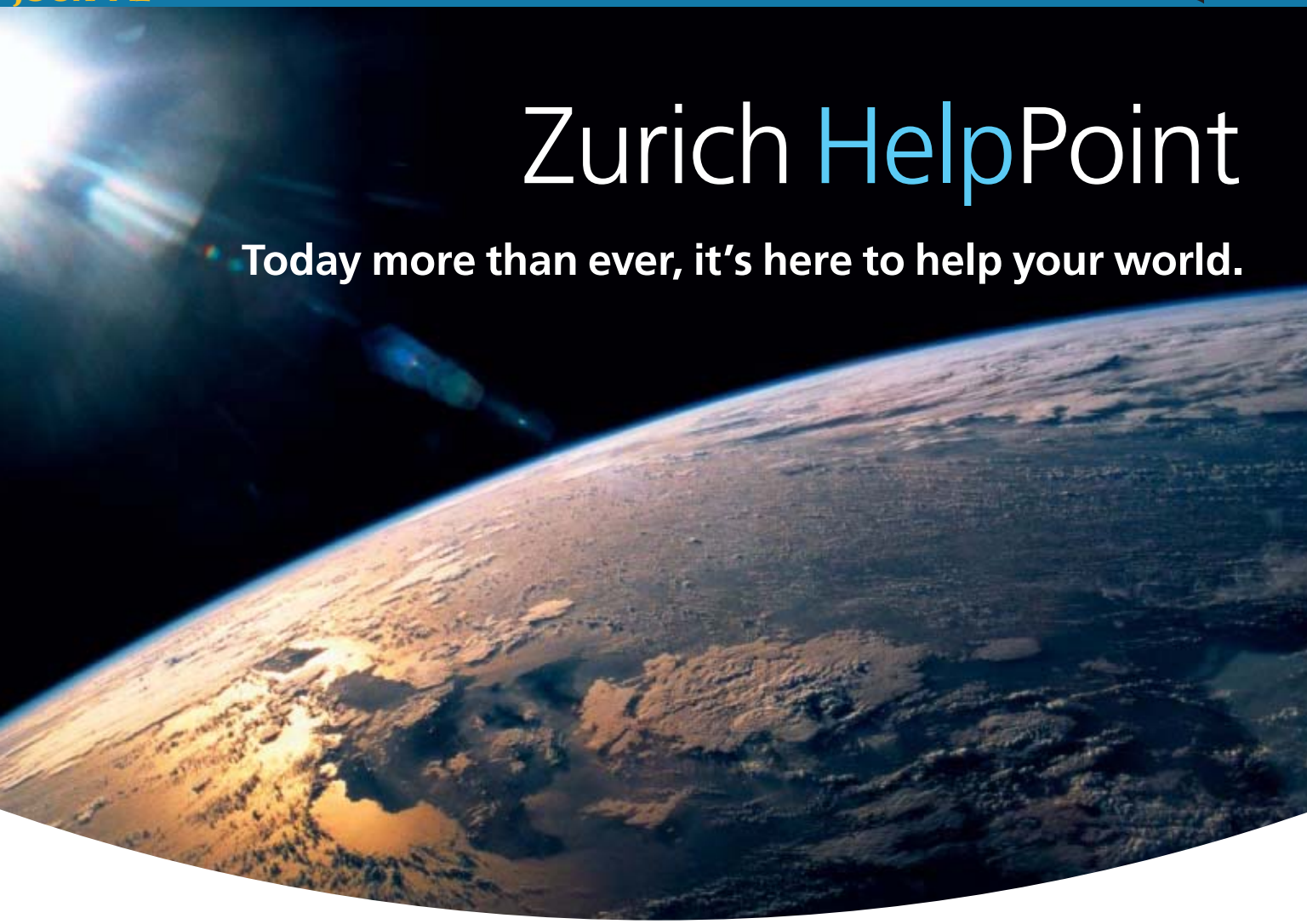


Note: Monthly average count

BAKER HUGHES RIG COUNT: US / CANADA



Note: End of week average count



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the Oligocene section. It is less than 3 miles northeast of the Dione discovery announced in October 2008.

First production from the group's PSVM development is targeted in 2012.

BP Exploration (Angola) Ltd. is operator with 26.67% interest. Esso Exploration & Production Angola (Block 31) Ltd. has 25%, Angola's state Sonangol P&P 20%, Statoil Angola AS 13.33%, Marathon Oil Corp. 10%, and Total's TEPA (Block 31) Ltd. 5%.

Talisman makes oil discovery in North Sea

Talisman Energy Norge AS plans to drill an appraisal well to determine the size of its oil discovery in the Norwegian North Sea.

On test, wildcat well 15/12-21 flowed an average of 197 cu m/day of gas through a 20/64-in. choke. The well found a 133-m column in Middle Jurassic and Upper Triassic reservoir rocks and is 16 km north of Varg field and 15 km south of Sleipner Ost field.

Extensive data collection and sampling have also been carried out. "The size of the discovery has not yet been clarified because the oil-water contact was not proven," said Talisman. If profitable resources are proven, the discovery could be tied in to the Varg field.

Talisman drilled the well to a TVD of 3,268 m below the sea surface using the Maersk Guardian drilling rig and it ended in the Skagerrak formation in the Upper Triassic. The well was drilled in 86 m of water.

The discovery is on production license 038, which was awarded in the third licensing round in 1975.

Maersk Guardian will now drill appraisal well 15/12-21 A on the production license.

Prince Edward Island exploration planned

Ardent Resources Canada Ltd., private Pittsburgh operator, will drill two exploration wells on Canada's Prince Edward Island under an agreement with PetroWorth Resources Inc., Calgary.

By drilling two wells on the eastern part of the island, Ardent Canada will earn a 50% interest in six permits that cover 444,000 acres. The first well is to be drilled by yearend, and the second is due within 6 months after completion of the first.

Ardent, owned by Christopher Robinson and David Copley, operates in Pennsylvania, New York, West Virginia, and Ohio and holds interests in more than 300 wells. The principals also have a good grasp of the geology of the Maritimes basin and its many similarities to that of the Appalachian basin.

PetroWorth shot 304 line-km 2D and 108 sq km of 3D seismic on the lands. In recent months, some of this data underwent a new leading-edge method of interpretation that resulted in the identification of a potentially large natural gas anomaly on one of the PetroWorth licenses.

Vegas group tests oil in new Egyptian strike

Vegas Oil & Gas SA tested an average of 2,809 b/d of oil from two pay zones in the Geyad-1X exploration well in Egypt. The company is completing the well as a potential producer.

The well produced 40° gravity oil with 3.04 MMscfd of gas on sustained tests of Miocene Kareem sandstones through a 1-in. choke.

"The lower pay zone in the Kareem Rahmi formation is a net 19 ft thick. The lower Kareem Rahmi formation zone has been tested at a sustained rate of 1,174 b/d and 1.324 MMscfd," said Circle Oil, a partner in the well.

The upper pay zone in the Kareem Shagar formation is a net 10 ft thick but was not tested separately.

The onshore well is on the 400-sq-km North West Gemsa concession, 300 km southeast of Cairo in the Gulf of Suez basin.

The rig, Mubarak-1, will be moved to drill the SE-3 appraisal well in Al Amir oil field on the same concession, where Vegas began production earlier this year (OGJ Online, Mar. 2, 2009).

The concession agreement includes the right of conversion to a production license of 20 years, plus extensions, in the event of commercial discoveries.

Partners are Vegas Oil & Gas, 50%, Circle Oil PLC, 40%, and Premier Oil PLC, 10%. ✦

Drilling & Production — *Quick Takes*

Collaboration needed for N. Sea decommissioning

Operators in the southern UK North Sea must find quick and cost effective means to decommission oil production facilities, according to trade association Oil & Gas UK.

Decommissioning more than 300 platforms, 13,000 km of pipeline, and 800 wells in the UK and Dutch sector of the southern North Sea offers the potential for new technical solutions. Projects are already under way in the area.

Paul Dymond, OGUK's operations and supply chain director, expects to see a critical mass of decommissioning activity within the next 5 years. Collaboration between asset owners and effective communication with the supply chain is important to underpin smarter and more cost effective decommissioning, he said at a decommissioning conference in Newcastle, UK.

Gunther Newcombe, head of decommissioning at BP PLC, recommended that contracting strategies, simplification, and the transfer of best practice from the Gulf of Mexico would stimulate industry to innovate and drive costs down.

Win Thornton, Chevron Corp.'s manager of international decommissioning, added that a steady stream of projects over 2 decades in the Gulf of Mexico had created a well-developed market for decommissioning. But managing the process is difficult as operators must handle the work breakdown structure, onshore disposal and management, and different contracting strategies.

Protestors force output slow-down in Amazon

Pluspetrol Norte has reduced production at one of two oil blocks in Peru and state energy company Petroperu may have to halt work at its Iquitos refinery in the Amazon due to protests by indigenous people.

"The position in respect to our operations has worsened since we last released information on May 19," Pluspetrol Norte said.

"We have had to reduce our production due to a lack of storage space, and due to the ongoing situation in which we can't trans-

port petroleum on the North Peruvian pipeline," said the company, which produced about 32,000 b/d from the two fields in March: 16,099 b/d from Block 1-AB and 15,511 b/d from Block 8.

"Due to the reduction in production we have been obliged to temporarily suspend the presence of our workers, suppliers, and contract workers in the oil fields," the company added.

Pluspetrol Norte also warned that continuation of the protests could eventually affect the normal supply of oil to the government-run refinery in Iquitos.

Blocks 1AB and 8 lie in northern Peru, where indigenous communities have been protesting against a series of nine new investment decreed by the government, saying the decrees will lead to a private-sector takeover of their lands, along with their underlying mineral rights.

In addition to the oil pipeline, the 65-member tribes of the Peruvian Jungle Interethnic Development Association have blocked highways and waterways across six jungle provinces since early April.

Apart from seeking repeal of the nine decrees, the tribes also want the government to revise oil concessions in the Amazon jungle and establish reserves for so-called "uncontacted" tribes that live there in voluntary isolation.

Peru President Alan Garcia, who earlier this month declared a state of emergency and suspended some constitutional rights in the four provinces most affected, said his government's nine decrees are nonnegotiable. "The lands of the Amazon belong to the entire nation, not to the small group that lives there," Garcia said.

Jackson's visit includes look at Jonah gas field

US Environmental Protection Agency Administrator Lisa P. Jackson completed a 2-day tour of Wyoming on May 21 that included a stop at the state's largest developed unconventional natural gas field.

The federal official also toured a wind farm near Cheyenne and a coal mine near Gillette and flew over a number of coalbed methane developments. Wyoming is currently the nation's largest net exporter of energy, the EPA noted.

Jackson visited Wyoming at the invitation of Gov. Dave Freudenthal (D). "I appreciate her willingness to take the time to visit our state and see on the ground how coal, natural gas, and wind power are produced here," he said as the visit concluded.

"This was an important opportunity for us to discuss issues including carbon sequestration, the management of water produced in coalbed methane development, and the technologies used to recover natural gas in unconventional fields in Wyoming," Freudenthal added.

Jackson stopped at the Jonah field, which contains an estimated 10.5 tcf of tight sand gas, on the second day of her visit. "Wyoming is a place where economic possibilities, environmental and human health concerns, and the pursuit of energy independence all come together.

"As a home of wind, coal, and natural gas, Wyoming is at the heart of America's energy future," she said before returning to Washington. ✦

Processing — *Quick Takes*

Iran to help Uganda construct refinery

Uganda President Yoweri Museveni, siding with officials of his government against plans by international oil companies, said his country will build a domestic refinery with Iranian assistance.

"We are more inclined to building a refinery than exporting unprocessed crude oil," he said, coming down against Tullow Oil and its partner Heritage Oil, which prefer construction of an oil pipeline from their fields in Uganda to the Kenyan port of Mombasa to export crude.

Iran and Uganda reached an agreement concerning the refinery project, as well as other oil and gas developments, during a 3-day visit by Museveni to Tehran, where he held talks with Iran's President Mahmoud Ahmadinejad.

A communique issued at the end of Museveni's visit said Iran had signed a cooperation agreement that included funding for the entire "value chain" of Uganda's oil production.

"Regarding the field of energy in particular, the two leaders agreed to consider cooperation in building an oil refinery in Uganda," the communique said, adding, "Iran also expressed its readiness to invest in the entire value chain of Uganda's petroleum industry."

Ugandan officials have long disagreed with the views of Tullow and its partner Heritage Oil over the need to construct an oil refinery versus an export pipeline.

"Our objective is to process the oil. We don't want to export it. Our aim is to get an economic return, to get jobs (and) investment. We don't want anything raw to get out," said Uganda's energy minister Hillary Onek at the recent East African Petroleum Conference in Mombasa.

But Heritage vice-president for exploration and production, Brian Smith, demurred on the idea of a full-scale refinery for Uganda, saying that estimated production was not high enough to justify the 100,000 b/d, $1.3 billion plant the Ugandans were reported to be considering (OGJ, Mar. 16, 2009, p. 40).

Gassco briefly closed Kollsnes gas plant

Gassco AS briefly shut its 143 MMscmd Kollsnes gas processing plant on the Norwegian North Sea coast because of a condensate leak.

The production disruption temporarily increased British gas prices. No personnel were injured during the incident.

"The point of leakage has been identified, and preparations for repair work have started," said StatoilHydro, which provides technical services to the plant. A company spokeswoman told OGJ that the cause of the leak remained unknown.

StatoilHydro is providing gas from other sources for its customers while repairs are under way.

The processing plant at Kollsnes, west of Bergen, treats gas from Troll, Kvitebjorn, and Visund fields. Installation of a sixth export compressor in 2005 expanded the plant's capacity from the original 120 MMscmd.

New resid FCC unit in Taiwan due CO boiler

CTCI Corp., Taipei, has let a contract to subsidiaries of Foster Wheeler AG for supply of a carbon monoxide boiler for a new 80,000-b/d residual FCC unit at CPC Corp.'s Talin refinery in Kaohsiung, Taiwan.

CTCI is the engineering, procurement, and construction contractor for the resid FCC unit. The 300,000-b/d Talin refinery is near to but independent from CPC's 220,000-b/d Kaohsiung refinery and petrochemical complex.

Foster Wheeler will provide an incinerator to destroy CO in the RFCC waste-gas stream, a boiler section to recover heat from the resulting flue gas, and a selective catalytic reduction flue-gas treating system to reduce emissions of nitrogen oxides. ✦

Transportation — *Quick Takes*

Abu Dhabi crude export pipeline progresses

Germanischer Lloyd (GL) announced it will provide technical assurance and certification of the 400-km, 48-in. OD Abu Dhabi Crude Oil Pipeline (ADCOP). The line will transport 1-1.5 million b/d of oil to the main oil terminal (MOT) at Fujairah, UAE, from Habshan, Abu Dhabi, bypassing the Straits of Hormuz in the process. The 1.5 million b/d figure represents roughly 60% of the UAE's crude exports.

ADCOP also includes construction of 12 million bbl of storage at MOT, three subsea pipelines, a main pumping station, intermediate pump station, and three single-point mooring buoys for deepwater tanker loading at Fujairah on the Indian Ocean coast. Construction is scheduled to be completed in August 2011.

GL's services on the project include third-party inspection both during and after construction, nondestructive testing, and issuing a certificate of compliance for the entire project. China Petroleum Engineering & Construction Corp. (CPECC), ADCOP's main engineering, procurement, and construction contractor, awarded the technical assurance, risk and safety, asset management, and industrial inspection contract to GL.

CPECC awarded detailed engineering on ADCOP to Penspen in 2008.

Pakistan, Iran sign gas pipeline agreements

Pakistan President Asif Ali Zardari and Iran President Mahmood Ahmadinejad signed an intergovernmental declaration May 24 to support within the framework of their respective laws and regulations the gas deal between the oil ministries of both countries.

Zardari is in Tehran for a three-way summit with Ahmadinejad and Afghanistan President Hamid Karzai.

A gas sale purchase agreement was signed earlier by managing directors of the National Iranian Oil Co. and the Pakistan Interstate Gas System, set up by the Pakistan government for the project.

The 2,100-km pipeline is to transfer Iranian gas to Pakistan. About 1,100 km of pipeline would be laid in Iran and 1,000 km in Pakistan. The project is to transfer about 750 MMcfd of gas. Construction of the pipeline is to be completed in 5 years.

Pakistan and Iran will sign the formal agreement for the multibillion dollar gas pipeline project in a third country within the next 15 days, according to Asim Hussain, top energy adviser to Islamabad, capital of Pakistan, and Pakistan leader on the pipeline project.

UPI wire service reported Iran and Pakistan are set to sign formal agreements on the Iran-Pakistan-India pipeline by June. In that deal, it said, Pakistan would take 2.6 bcfd from Iran's South Pars gas field over the next 25 years.

Second Chinese LNG terminal begins operations

China National Offshore Oil Corp. received the first LNG commercial cargo at its Fujian terminal earlier this month.

Unconfirmed reports said the cargo arrived aboard the 145,700-cu m Tangguh Towuti from Indonesia's Bontang liquefaction plant. BP's Tangguh project is contracted to deliver cargoes to Fujian but its opening has been repeatedly delayed. Fujian is to receive 2.6 million tonnes/year from Tangguh once the plant is operating.

Fujian is China's second terminal to begin operating. BP has operated the 6.2 million tpy Dapeng LNG terminal in neighboring Guangdong Province since 2006. The Fujian terminal was commissioned last year.

Later in 2009, CNOOC expects to open a third terminal, at Shanghai, that initially will be able to import 3 million tpy with expansion of another 3 million tpy on tap.

PNG signs landholder deal for LNG project

The government of Papua New Guinea has signed a benefits-sharing agreement with landowners concerning the ExxonMobil Corp.-led Papua New Guinea LNG (PNG LNG) project.

The agreement is worth about 20 billion kina, or about $9.5 million (Aus.), over the life of the project and gives provincial governments and landholders a 7% stake in PNG LNG. The central government will retain 12.5% interest.

The government has also committed to a number of infrastructure projects, including the construction of a sealed major highway linking the Gulf of Papua to the country's north coast. It will also seal the Gulf-Southern Highlands highway and put 100 million kina towards building the first phase of a Hela city development.

Meanwhile, it was reported that China' Sinopec is negotiating to buy 2 million tonnes/year of LNG from the project.

The project comprises a two-train, 6.3 million tpy liquefaction plant near Port Moresby with gas sourced from various gas fields in the highlands including Hides and possibly Juha.

ExxonMobil has 41.6% and operatorship of the project, Oil Search 34.1%, Santos 17.7%, and Nippon Oil 5.4%. Landholder interests hold the remaining 1.2%.

Papua New Guinea's state-owned Independent Public Business Corp. is using its 17.56% stake in Oil Search to raise $1.68 billion to fund the government's 19.4% share of the project which will then reduce the interests pro rata held by the other partners. ✦

The North Sea, 56 40.41 N, 2 56.19 E, 4:15 PM

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2009

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.

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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.

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.

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.

Energy education for kids

Leena Koottungal
Survey Editor/
News Writer

For an oil and gas researcher, finding information on encouraging young people to get excited about the industry is not difficult.

Acergy UK Ltd., an offshore engineering and construction company based in London, recently opened its office in Westhill, Aberdeen, Scotland, to about 350 area schoolchildren to help inspire the industry's next generation. The children were joined by older pupils from Westhill Academy to gain an insight into the industry.

"We hope the pupils have not only an improved understanding of the sector and the issues it faces but are also more aware of its importance and how they could potentially contribute in a few years," said Graham Meil, Acergy managing director.

This 1-day event divided children into 55 teams, allowing them to engage in team-building, problem-solving, and understanding industry topics. There were presentations on key subjects, including the global significance of energy, alternative power sources, and the importance of communication.

Beyond this hands-on approach are other methods and resources to educate children on energy industry topics.

Online information

The US Energy Information Administration encourages children to learn about energy through its Energy Kid's Page. This page contains energy facts and history, games, conversion calculators, classroom activities, links to other educational sites, and a glossary.

The energy facts are in a quick-take format on topics such as renewable and nonrenewable sources of energy, electricity, hydrogen, uses of energy, the science of energy, and saving energy.

The Energy Ant is the tour guide for the page and even takes children on various field trips. The ant presents a travel log of energy locations such as BP's Carson refinery and Hoover Dam Hydroelectric Plant while providing historical and operations information on the facilities using nontechnical explanations.

The kid's page explains energy slang, including everyday words with specialized meanings in the industry such as "pig," "can," "christmas tree," and "wildcat." It defines 24 terms with a visual of each word.

Competitions, scholarships

The US Department of Energy has a section on its web site dedicated to students and children that offers details on contests, competitions, scholarships, and internships.

One competition is the Junior Solar Sprint/Hydrogen Fuel Cell Car competition. Middle school teams work together to build solar or hydrogen fuel cell cars with guidance from a parent or teacher to compete in race and design categories.

A Spirit Award is also presented to the team recognized for good sportsmanship. Building solar and hydrogen fuel cell cars for the competition requires skills in both math and science. The primary goals of the program are to generate enthusiasm for science, technology, engineering, and math at a crucial stage in the development of young people. The competition also helps improve students' understanding of scientific concepts and renewable energy technologies while encouraging them to consider technical careers at an early age.

This section of the site also provides a long list of scholarships and internships as well as links to several other energy-related web sites for young people.

Resources for educators

American Petroleum Institute, in partnership with Project Learning Tree, an award-winning environmental education organization, has developed the "Energy and Society" K-8 education program. The program's multidisciplinary education materials help students understand the critical role energy plays in their lives. Program components include a music CD, dance video, posters, study guide, and web site. The CD is a collection of 15 energy-related songs such as "Energy & Me" and "We Can Save Energy" by Billy B., a natural science song and dance man. The video features dances to five of the songs.

API has also teamed up with the American Association for the Advancement of Science to create a series of online lesson plans and interactive modules focusing on the mechanics and complexities of energy transformation and on the technological advancements being made in energy conversion. The series has separate sets of lessons for grades 6-8 and grades 9-12.

US Minerals Management Service also has a kid's page on its web site with a role-playing exercise called "Watts it to you?" Students assume the role of a government official, energy company executive, environmentalist, and local business person to work together to develop a county energy plan to increase the amount of electricity produced locally.

These resources mentioned are just a taste of what is available to promote learning about energy and to inspire young people to become involved in the energy industry. ✦

Editorial

FIRST OF TWO PARTS

A costly energy course

Policy can encourage development of nontraditional energy forms as either supplements to or replacements for traditional forms. Economically, the approaches are poles apart.

The administration of US President Barack Obama has confirmed plans to commit the country to the costlier option and welded its motives to the mitigation of climate change. Soon to be bonded in policy, unless economic judgment prevails, are two uncontrollably expensive programs offering proportionally small benefits.

'Overproduction'

Long-implied intention became explicit in the Treasury Department's discussion of a proposed federal budget that would raise taxes on the oil and gas industry by $50 billion over 10 years. Tax preferences favoring oil and gas companies, Treasury said, compromise energy security by encouraging "overproduction" of oil and gas. In each case, "The [measure or its result], like other oil and gas preferences the administration proposes to repeal, distorts markets by encouraging more investment in the oil and gas industry than would occur under a neutral system." Treasury called this circumstance "inconsistent with the administration's policy of encouraging the use of renewable energy sources through a cap-and-trade program [to reduce emissions of carbon dioxide]."

To resist global warming, then, the administration will encourage development of renewable energy in place of rather than in addition to domestic production of oil and gas, which it will discourage with taxation. Unbelievable.

Contrary to Obama's blandishments about "green jobs," displacement on meaningful scale of economic energy with costlier substitutes can't happen except at great cost. A two-part editorial series beginning here will attempt to put the effects into perspective. The first part will examine proposed energy shifts in the context of subsidies already pouring toward renewable sources. Next week's installment will report estimates of costs for the cap-and-trade scheme before Congress.

Try though it will, the government can't reengineer energy markets efficiently by decree. Efforts in this direction breed handout Hydras like the fuel-ethanol program and create a paradise for subsidy profiteers.

A report last year by the Energy Information Administration offers a basis for extrapolating the costs of deliberately raising the use of renewable energy to the detriment of oil and gas. According to EIA, US subsidies for the production of renewable energy used for electric power generation in 2007 amounted to 82¢/MMbtu. But that encompasses all renewable energy, including sources such as relatively low-subsidy, high-output hydropower, which won't grow much. In the dominant political vision of the day, oil and gas give way to solar energy, wind, and biofuels.

In 2007, production subsidies for solar amounted to $7.16/MMbtu and for wind, $6.87/MMbtu. Consumption subsidies for ethanol, the main biofuel, were worth $5.72/MMbtu. Because the blending tax credit for ethanol has fallen since then, the subsidy this year will be worth about $5.42/MMbtu. While these values aren't perfectly comparable, they do indicate what's required to move these energy forms into commercial markets.

For simplicity, the assumption here is that subsidies for fuels favored by politicians average $6/MMbtu in value over the next 10 years. So how much would the US spend in subsidies alone to cut oil and gas usage rates by, say, 5% each below forecast levels by the end of the budget period and make up the difference with renewable energy?

Moving the needle

Based on EIA projections for 2020, the cuts would be 1.83 quadrillion btu (quads) for oil and 1.1 quads for gas. Subsidies for the replacement energy thus would come to $17.6 billion. That 1-year total is more than the entire annual budgets for some federal departments. And the hypothetical spending would move the energy needle by just 5%.

Fiscal damage wouldn't end at $17.6 billion. Supplanted oil and gas otherwise produced domestically, for example, would generate no royalty and no tax revenue. And the US still would use 17 million b/d of oil and 61 bcfd of gas—probably not what proponents of these moves have in mind. Costs postulated here take no account of even greater economic sacrifice required by the cap-and-trade program, the subject for this space next week. ✦

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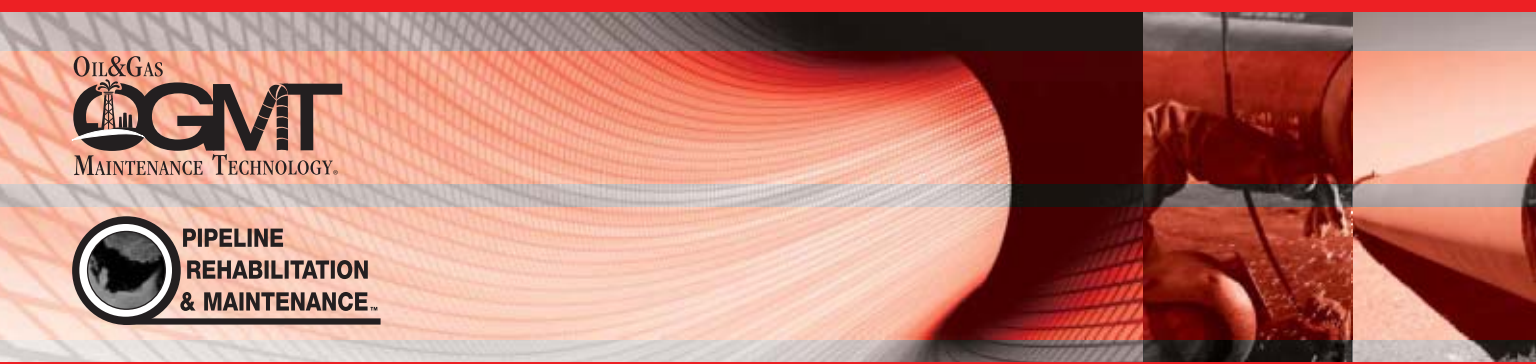

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SECOND OF TWO PARTS

Alaskan tax reform: Gas raises questions

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The question whether success of Alaskan tax reform with oil foretells comparable success with natural gas hinges on a side effect of high progressivity: a very high marginal rate. As noted in the first part of this series, as the progressivity charge rises it affects the tax rate applied to all the taxed hydrocarbons (OGJ, May 25, 2009, p. 20).

This effect is most pronounced, for example, when the production tax value (PTV) is around $92.50/bbl, when about 93¢ of an extra $1/bbl of revenue goes to the state. Why? Before adding the extra dollar, the base production tax (BPT) was 25%, and the combined progressivity tax (CPT) was 24.6% for a total of 49.6%. Adding 0.4% times $92.5 is only 37¢/bbl more in tax—but that is 37% of the additional dollar that triggered the higher tax. Add the 49.6% to that 37% and, on different bases, 12.5% royalty, 9.4% income tax, and 2% property tax, and you have reached 93% (Table 1).

The table shows the maximal marginal impact on the government's take of a $1 increase in oil price on a high production tax value field. The government takes most of the financial gains from an incremental price increase at high oil prices. Below $92.5/bbl the marginal effect will be smaller.

Such circumstances could encourage producers to gold-plate field costs in order to lower PTV. Incremental costs are met mainly by the state with every additional dollar per barrel of spending potentially offsetting the increased state take from an extra dollar per barrel of revenue (Table 2). The government revenue share absorbs most of the incremental investment at high oil prices. Actually, once investment credits are factored in and even with no boost from royalty, the marginal rate (or state underwriting of the investment) can reach the vicinity of 100%.

These prices have been chosen to illustrate an extreme point: In general for energy scenarios with both higher and lower values the marginal tax rate falls. The rest of this article focuses on one scenario likely to lead to a much lower marginal tax rate: A producer of oil adds a significant gas stream to its portfolio.

Taxes, gas sales

How will this tax work in conjunction with a major gas sale? The progressivity mechanism has been through one test (high oil prices), and from the state's point of view it worked. Prices went to levels in 2008 only previously dreamed of, and the progressivity mechanism worked to produce the intended result of a significantly higher state take.

However, modeling suggests there may be other tests ahead with less felicitous outcomes. The state hopes that more than 35 tcf of proved gas on the North Slope, plus more yet-to-find gas, can be monetized, and continues to explore ways to bring about its commercialization. If a gas line (or other

MAXIMAL MARGINAL IMPACT OF INCREMENTAL $1/BBL OF WEST COAST ANS OIL PRICE INCREASE

Table 1

Formulas	Simplified ($/bbl) analysis	Base case	+$1 price	Difference
A	Destination price West Coast	$120.36	$121.36	$1.000
B	Less transportation costs (TT&T)	$6.00	$6.00	
A – B = C	Gross value at point of production (PPV)	$114.36	$115.36	$1.000
D	Royalty (12.5% of gross value)	$14.30	$14.42	$0.125
E	Less upstream costs	$20.00	$20.00	
C – D – E = F	PTV or net value	$80.07	$80.94	$0.875
G	Taxable barrels (exclude 12.5% royalty)	87.5%	87.5%	
F/G = H	PTV/taxable barrel	$91.50	$92.50	
(H – 30)*0.004 = I	Production tax progressivity (CPT %) (see note)	24.60%	25.00%	0.339%
J	Base production tax (25%)	25.00%	25.00%	
I + J = K	Total production tax rate (%)	49.60%	50.00%	0.399%
F*K = L	Precredits production tax (rate*PTV)	$39.71	$40.47	$0.757
M	Production tax credits (assumed)	–$10.00	–$10.00	
N	Property tax (assumed)	$0.50	$0.50	
F – (L + M + N) = O	Simplified income tax base ignoring worldwide income (CIT) and different depreciation mechanisms for CIT & FIT			
O*9.4% = P	State income tax (9.4%*net less taxes)	$4.69	$4.70	$0.011
(O – P)*35% = Q	Federal income tax (35%*net less taxes)	$15.81	$15.85	$0.037
D + L + M + N + P + Q = R	Government take including CIT & FIT	$65.00	$65.93	$0.931
D + L + M + N = S	Government take excluding CIT & FIT	$44.51	$45.39	$0.882

NOTE: A different progressivity formula applies when H is below $30 or above $92.50.

gas revenue-generating project) were in place, how would the prevailing CPT mechanism operate? The gas sold would be converted to oil on a barrel-of-oil-equivalent basis and taxed using the progressivity mechanism. What are some of the consequences of that?

The general effect for any taxpayer with gas and oil production might be that adding gas production actually lowers production tax liability. Why? Consultants for the current administration have suggested that the gas-line tariff is likely to be about $5/MMbtu, which translates into a tariff of $30/boe of gas. Even if oil and gas were sold and taxed at a btu parity in the market, a $30/boe transportation deduction for gas would compare to an average cost to market of about $6/bbl for oil. PTVs will be much lower for combined oil and gas streams than they are for oil-alone streams.

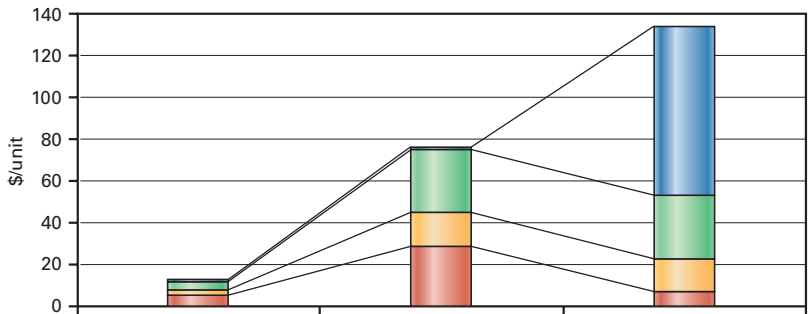
This point is illustrated in Fig. 1, which shows that a lack of oil and gas price parity and quite different downstream and upstream cost structures mean that, using energy prices found in, say, June 2008, under current CPT mechanisms Alaska gas would pay little or no CPT, whereas Alaska oil would pay substantial CPT. Blending the two streams together results in gas diluting the CPT computation and cross-subsidizing oil.

However, as the figure also illustrates, the notion of oil and gas selling at a btu parity is elusive. As the world has found, oil and gas prices do not always move in tandem. Ignoring location differentials, for more than a year from the summer of 2007 through the summer of 2008, the ANS monthly price was more than 12 times the Henry Hub benchmark price for natural gas and double the btu-parity relationship.

At those parities it is possible to construct scenarios where Alaska could achieve its long-held dream of a gas pipeline but generate less production tax revenue with a gas pipeline than without it. How? Because of the fall in progressivity that comes about when oil and gas are combined in the CPT calculation.

Alaska oil, gas production tax values, June 2008

Fig. 1



	1 MMbtu gas	1 boe gas	1 bbl oil
Subject to progressivity tax	0.25	1.50	81.25
$30/boe PTV excluded from CPT	5.0	30.00	30.00
Upstream costs	2.71	16.26	16.26
Downstream costs	4.73	28.38	6.27

Source: Data sources available from the authors

Gas with oil

Fig. 2 illustrates the production tax consequences of a wide range of oil and gas PTV dollar-per-barrel-of-oil-equivalent combinations but focuses on

Maximal marginal impact of incremental investment of $1/bbl of capital

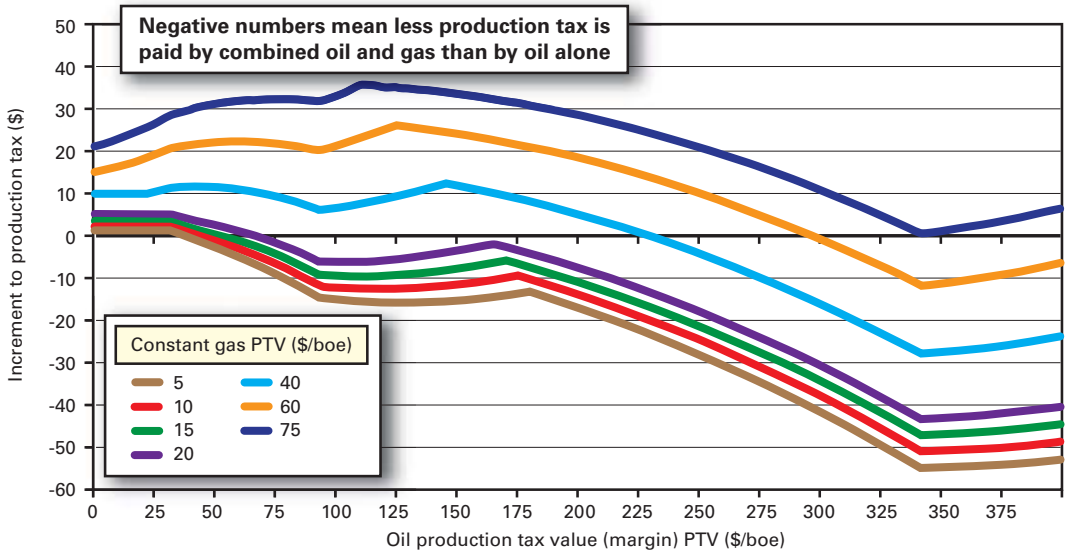
Table 2

Formulas	Simplified ($/bbl) analysis	Base case	+$1 capex	Difference
A	Destination price West Coast	$121.36	$121.36	
B	Less transportation costs (TT&T)	$6.00	$6.00	
A – B = C	Gross value at point of production (PPV)	$115.36	$115.36	
D	Royalty (12.5% of gross value)	$14.42	$14.42	
E	Less upstream costs	$20.00	$21.00	$1.000
C – D – E = F	PTV or net value	$80.94	$79.94	–$1.000
G	Taxable barrels (exclude 12.5% royalty)	87.5%	87.5%	
F/G = H	PTV/taxable barrel	$92.50	$91.36	$1.143
(H – 30)*0.004 = I	Production tax progressivity (CPT %) (see note)	25.00%	24.54%	–0.456%
J	Base production tax (25%)	25.00%	25.00%	
I + J = K	Total production tax rate (%)	50.00%	49.54%	–0.456%
F*K = L	Precredits production tax (rate*PTV)	$40.47	$39.61	–$0.865
M	Production tax credits (assumed)	–$10.00	–$10.10	–$0.100
N	Property tax (assumed)	$0.50	$0.50	
F – (L + M + N) = O	Simplified income tax base ignoring worldwide income (CIT) and different depreciation mechanisms for CIT & FIT			
O*9.4% = P	State income tax (9.4%*net less taxes)	$4.70	$4.69	–$0.003
(O – P)*35% = Q	Federal income tax (35%*net less taxes)	$15.85	$15.83	–$0.011
D + L + M + N + P + Q = R	Government take including CIT & FIT	$65.93	$64.95	–$0.979
D + L + M + N = S	Government take excluding CIT & FIT	$45.39	$44.43	–$0.965

NOTE: A different progressivity formula applies when H is above $30 or below $92.50.

ALASKA PRODUCTION TAX DILUTION EFFECTS OF GAS*

Fig. 2



*The production tax implications of combining revenue streams of 1 boe of gas with 1 boe of oil over a range of production tax values according to prevailing Alaska production tax rules. Negative values on the vertical axis illustrate where the combined oil and gas revenue streams pays less production tax (BPT + CPT) than an oil-only stream: i.e., where low-value gas revenue streams could reduce the overall production tax paid by an oil revenue stream. Increment to production tax is (oil + gas BPT + CPT) less (oil BPT + CPT).

the impact of adding a single low-PTV $/boe gas barrel to an oil barrel varying in PTV from $0/boe to $400/boe. Gas revenue streams from PTVs below $20/boe reduce the overall production tax paid by an oil revenue stream by the CPT mechanism over most of the oil PTV $/boe range above the CPT threshold of $30/boe. Negative values in the figure illustrate where the combined oil and gas revenue stream pays less production tax (BPT + CPT) than an oil-only revenue stream.

Of course, the whole idea behind a net tax is that investment gets a boost from its favored tax status. Investment in producing more oil and gas should lower taxes. However, the upstream infrastructure to produce most of the gas that would feed a gas line has already been developed. State policymakers might think about oil and gas as a combined stream and be perfectly sanguine that adding the lower-value gas to Alaska's production portfolio may enhance development by increased tax incentives.

On the other hand, if state policymakers continue to think about distinct oil and gas streams, then as a consequence of these high oil-only marginal rates there are some potential outcomes waiting in the way the CPT works that they may be less comfortable with.

More important, though much less open to illustrative modeling, is the effect the tax, including some of the outcomes illustrated above, will have on reinvestment. For example, looking at Fig. 2 and assuming a constant gas PTV, consider a producer evaluating an investment that will also lower the oil PTV in the year of that investment. Sometimes that increased oil investment will lead to a higher relative tax (i.e., moving from right to left on a portion of the illustrated curve that has a positive slope), and sometimes it will lead to a lower relative tax (i.e., moving from right to left on a negatively sloped portion of the curve).

How companies make long-term investment decisions, and how those decisions fit in with taxes and tax stability remain huge unknowns to state policy-makers. Figs. 3 and 4 illustrate how reinvestment leads to complex variations in production tax liabilities under the prevailing production tax methodology.

Fig. 3 shows that the nonlinearity of the CPT mechanism results in different impacts of capital reinvestment on a producer's CPT liability depending on the prevailing PTV dollar per barrel. Production tax rates for producers can be substantially reduced over a wide range of PTV $/boe (above the $30/boe CPT threshold) by reinvestment of post-tax dollars.

Fig. 4 shows the percentage tax reduction associated with the incremental reinvestment (or the marginal tax rate offset by the producer by its reinvestment). Note the peak around PTV $90/boe and values above 100% at PTV $350/boe. These high marginal tax rates should act as significant incentives for reinvestment. However, the nonlinearity of the benefits and steep gradients complicate prediction and tax planning for investors. Generally, incentives for reinvestment are higher when PTV is higher.

Future response

How might Alaska respond to these production tax issues? History sheds light on how Alaska's fiscal design could evolve in the future. The period 1973-81 was a time of huge turmoil in Alaska's fiscal system for royalties and all three oil and gas taxes.

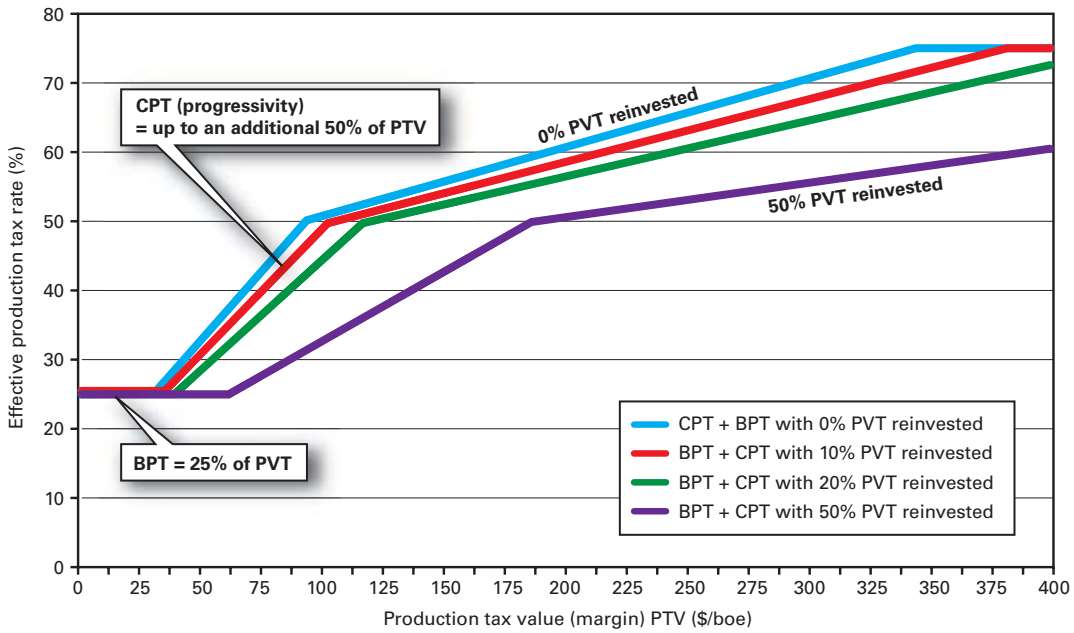
The driving event was the opening of the trans-Alaska pipeline in June 1977. The period started with a special legislative session in which the state added the statewide oil and gas property tax to its fiscal take. It also created a special oil and gas corporate income tax based on separate accounting (taxing only profits earned in Alaska), and then 4 years later switched back to

apportionment of worldwide earnings—with special rules for oil and gas companies.

In 1977 the state filed a lawsuit against royalty payers that was not resolved for 18 years but the settlement of which finally set out the rules for calculation of royalties. In this period the state changed the production tax several times, going from stair-step production rates driven by well size to various versions of the economic limit factor (ELF). Outside of oil and gas law, but driven by the receipts from those royalties and taxes, the state also repealed its personal income tax and gross receipts business tax and began distributing some of the state's oil wealth directly to its citizens in annual checks that have ranged from $331.29 in 1984 to $3,269 in 2008. Will the period of transition from North Slope oil to North Slope gas be as tumultuous?

ALASKA PRODUCTION TAX RATES (BPT PLUS CPT %)

Fig. 3



Stability concerns

This prospect of fiscal instability may appear daunting to potential investors in a North Slope gas line and future exploration and production activities. Many public statements can be heard these days that the state is staking its fiscal future on a gas line.

In 2007 there was a great fuss when the extra oil taxes paid for 2006 as a consequence of the first round of reforms were about 14% below anticipation. What would happen if the long-awaited gas line were built and instead of proving to be the financial future of the state it actually lowered production tax revenues?

The history of the past 3 decades leads these authors to conclude that such an outcome would more than likely lead to revisions in the tax code; fear of such changes has often been cited by leaseholders. As an alternative, if Alaska were to establish a stable fiscal design for natural gas in advance of contractual commitments associated with a gas line being made, it might make those commitments more likely.

Fiscal stability issues that have arisen around the world in the past 5 years have highlighted that fiscal stability clauses in contracts and licenses do not guarantee long-term fiscal stability and are easily circumvented by those prepared to exert political pressure on producers. An alternative approach to attempting to lock in fiscal stability via legislation or contract is to establish a rational tax system tied to a long-term, widely agreed upon state fiscal strategy and associated policies and targeted incentives.

With all stakeholders recognizing the objectives of the stated strategy, it should be possible to secure investments in the relative security from an investor's perspective that short-term changes to fiscal terms are not going to be made as short-term reactions to changing market conditions. A rational tax system appropriate to such a strategy would need to be flexible and predictable and contain the following elements:

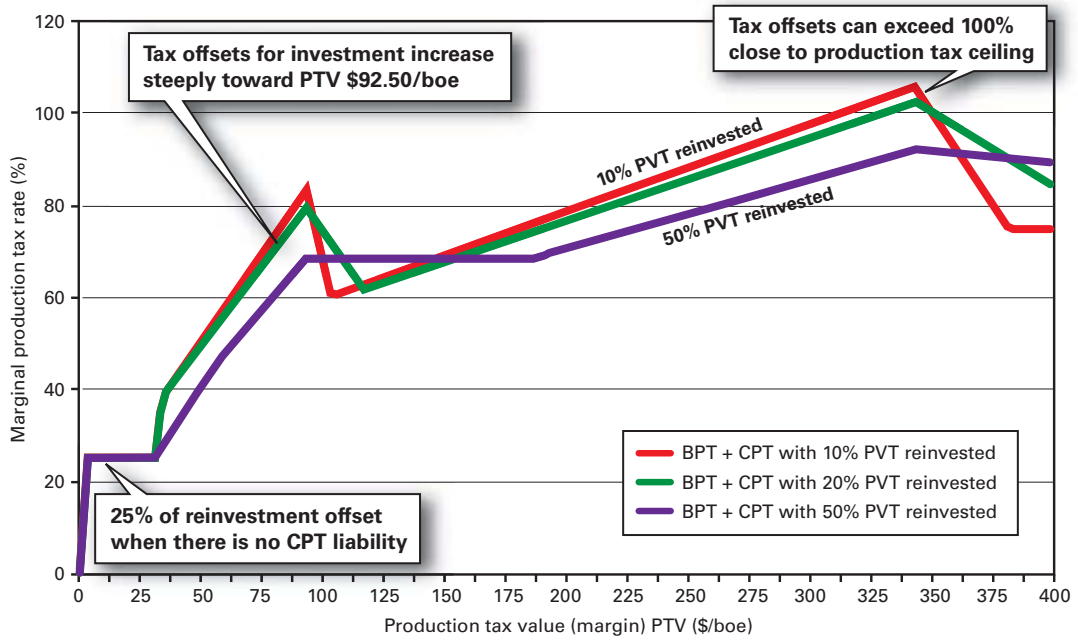
- Some regressive elements targeted specifically at high-volume production that provide the state with a baseline revenue stream regardless of prevailing prices.
- Some progressive elements that only impact the producers when prices are such that substantial net revenues can be secured by producers while also providing the state with higher net takes from high-margin production.
- Targeted allowances to the regressive elements that stimulate capital investment in higher-cost, difficult fields.

Importance of balance

Systems with a balance of all three components are more likely to be efficient in raising taxes and promoting investment in a wide range of market and reservoir conditions without prompting frequent fiscal restructuring by a government. If the state's long-held and widely articulated belief is that taxes from oil and gas should provide the baseline revenues needed to run the state, then in a low-price environment a

PERCENTAGE OF PRODUCER PTV REINVESTMENT OFFSET BY ALASKA PRODUCTION TAX LIABILITY CUTS

Fig. 4



fiscal mechanism driven solely by progressive elements cannot be considered a very stable approach.

Conversely, a fiscal mechanism dominated by regressive elements such as royalties and property taxes (without any allowances or investment incentives) will be ineffective at promoting investment in high-cost developments because of its negative consequences for producers in low-price environments and may even cause temporary shut-in or premature abandonment of marginal fields. The challenge for Alaska is to find the right fiscal balance soon for future gas revenues and to promote upstream investment to achieve long-term sustainable gas production a decade or more from now.

One of the alternatives to a CPT combined progressivity tax mechanism is a distinct oil progressivity tax (OPT) and gas progressivity tax (GPT). Typically, with no allowances, such an approach would have the effect of increasing the total progressivity taxes paid compared to the CPT approach.

However, incentives and allowances could be targeted and tailored specifically at more-marginal gas (or oil) streams to avoid inhibiting development capital investment. The point is that if the state is unlikely to be willing to live with a pipeline causing a significant drop in its fiscal revenues, a substantial drop in production tax revenue caused by a CPT mechanism conceived with oil in mind but diluted by gas is likely to lead the state to change the law.

The industry's perception of the possibility or likelihood of such a tax change to fix the issues posed by gas for a CPT mechanism is likely to provide its own inhibition to further development and investment in a gas line. ✦

First-quarter E&P earnings plummet on lower prices

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Lower oil and gas prices and increased costs sharply reduced the earnings of some US and Canadian producers in the first 3 months of 2009. At the same time, some producers benefited from lower costs. Also, refiners and marketers reported stronger earnings from a year earlier as a result of healthier margins and reduced costs.

A sample of 79 producers and refiners based in the US combined for a $9.5 billion loss in the first quarter of this year. This contrasts with earnings of $30 billion for the same group of companies a year earlier. In the recent quarter, 47 of the companies posted a loss—more than twice as many as incurred a loss in first quarter 2008.

Meanwhile, a sample of Canadian producers and pipeline companies recorded a decline in earnings and revenues for the quarter. Also, a group of service and supply companies posted a collective decline in first-quarter 2009 earnings and revenues as a result of a contraction in exploration and drilling activity.

Prices, margins

Weak worldwide oil demand brought on by the global economic recession caused prices to sink from their mid-2008 highs. In the first quarter of this year, the front-month contract

closing price of crude on the New York Mercantile Exchange averaged $43.31/bbl, down from $97.82/bbl a year earlier and down from $59.06/bbl in fourth quarter 2008.

Likewise, US natural gas prices plunged on weak demand by industrial and electric power customers and on rising supplies in storage. The front-month gas contract on NYMEX averaged $4.468/MMbtu in the recent quarter, down from $8.74/MMbtu in first quarter 2008.

Average US cash refining margins in the first quarter of 2009 moved sharply lower for Gulf Coast, Midwest, and East Coast refiners, but West Coast margins climbed 8% from a year earlier to average $15.04/bbl, according to Muse, Stancil & Co.

The Gulf Coast margin averaged $4.32/bbl in this year's first quarter, while the East Coast margin averaged $1.29/bbl, MSC reported.

US operators

The large, integrated US oil and gas producers posted positive but lower earnings in the first quarter, while many independent operators recorded losses.

But three of the oil and gas producers in a sample of US-based operators swung to a first-quarter profit from a loss position a year earlier. These producers are Abraxas Petroleum Corp., Belden & Blake Corp., and Goodrich Petroleum Corp.

Goodrich Petroleum reported that its first-quarter earnings were positively impacted by a $37 million gain on derivatives not designated as hedges, including a $21 million realized gain and a $16 million noncash, unrealized gain, compared with a $24.5 million loss on such derivatives in first quarter 2008. First-quarter production volumes were up 31% from a year earlier.

Meanwhile, just a few of the independents, including Cabot Oil & Gas Corp., Range Resources Corp., and others, reported an improvement in revenue and earnings from last year's first quarter.

Cabot said its recent earnings benefited from a gain on the sale of assets and a gain on derivatives. Range Resources' net income climbed to $32.6 million from $1.7 million due to noncash hedging gains.

ExxonMobil Corp.'s first-quarter earnings were $4.6 billion, down 58% from first quarter 2008 due to lower oil and gas prices and higher operating costs.

ExxonMobil's upstream earnings were $3.5 billion, down $5.282 billion from first quarter 2008, the company reported. Lower oil realizations reduced earnings by $4.4 billion, while lower gas prices cut earnings about $500 million. Higher operating expenses reduced earnings about $300 million.

US OIL AND GAS FIRMS' FIRST QUARTER 2009 REVENUES, EARNINGS

Table 1

	Revenues 1st quarter		Net income 1st quarter	
	2009	2008	2009	2008
	Million $ (US)			
Abraxas Petroleum Corp.	10.9	22.2	7.9	(19.7)
American Oil & Gas Inc.	0.3	0.5	(3.9)	(1.1)
Anadarko Petroleum Corp.	1,595.0	2,978.0	(331.0)	286.0
Apache Corp.	1,633.8	3,187.7	(1,756.9)	1,021.5
Approach Resources Inc.	10.1	19.0	0.9	2.8
Arena Resources Inc.	20.4	45.4	6.5	18.3
ATP Oil & Gas Corp.	82.1	268.2	3.6	46.8
Aurora Oil & Gas Corp.	4.2	6.8	(58.2)	(1.2)
Belden & Blake Corp.	17.1	34.3	13.2	(11.6)
Berry Petroleum Co.	183.2	170.9	35.0	43.0
Bill Barrett Corp.	144.9	149.7	26.4	30.6
Blue Dolphin Energy Co.	0.5	0.7	(1.0)	(0.5)
Brigham Exploration Co.	18.6	25.1	(119.1)	1.5
Cabot Oil & Gas Corp.	233.9	219.7	47.6	46.0
Callon Petroleum Co.	24.8	45.0	2.4	7.6
Cano Petroleum Inc.*	3.9	9.2	(0.7)	(1.0)
Carrizo Oil & Gas Inc.	31.2	53.6	(148.3)	(5.3)
Cheniere Energy Inc.	2.0	11.1	(82.7)	(49.9)
Chesapeake Energy Corp.	1,995.0	1,611.0	(5,740.0)	(130.0)
Chevron Corp.	3,613.0	65,946.0	1,854.0	5,196.0
Cimarex Energy Co.	209.2	477.2	(494.7)	149.5
Clayton Williams Energy Inc.	57.8	136.9	(21.3)	7.3
Comstock Resources Inc.	68.4	127.7	(5.6)	41.1
ConocoPhillips	31.3	56.6	856.0	4,158.0
Contango Oil & Gas Co.	36.3	21.7	0.8	112.7
Continental Resources Inc.	96.6	227.7	(26.6)	88.0
Delta Petroleum Corp.	59.3	66.4	(29.4)	(21.1)
Denbury Resources Inc.	173.8	317.3	(18.3)	73.0
Devon Energy Corp.	2,028.0	2,975.0	(3,959.0)	749.0
Dominion Energy Inc.	4,778.0	4,353.0	248.0	680.0
Dorchester Minerals Ltd.	8.8	21.3	3.8	15.4
Double Eagle Petroleum Co.	11.0	7.3	1.0	1.9
Dune Energy Inc.	14.3	36.7	(12.1)	(8.7)
Edge Petroleum Corp.	24.1	17.7	(76.9)	(16.2)
El Paso Corp.	1,484.0	1,269.0	(957.0)	228.0
Encore Acquisition Co.	114.3	272.9	(5.9)	31.3
EOG Resources Inc.	1,158.2	1,134.0	158.7	241.0
Evolution Petroleum Corp.*	1.2	0.9	(1.0)	(0.5)
ExxonMobil Corp.	64,028.0	116,854.0	4,550.0	10,890.0
FieldPoint Petroleum Corp.	0.6	1.5	(0.1)	0.3
Forest Oil Corp.	194.7	376.5	(1,177.8)	(4.7)
Frontier Oil Corp.	846.2	1,185.8	73.5	46.0
FX Energy Inc.	1.8	4.2	(24.4)	(4.3)
Gasco Energy Inc.	5.4	9.8	(43.9)	(4.4)
GeoResources Inc.	14.6	23.9	0.5	4.2
GMX Resources Inc.	22.8	27.2	(124.4)	6.2
Goodrich Petroleum Corp.	28.7	46.4	3.1	(25.5)
HKN Inc.	2.7	6.3	(1.1)	1.1
Helix Energy Solutions Group Inc.	571.0	441.8	107.2	74.0
Hess Corp.	6,872.0	10,700.0	(17.0)	752.0
Holly Corp.	653.0	1,483.5	23.9	9.5
Houston American Energy Corp.	0.5	2.9	(1.5)	0.9
Marathon Oil Corp.	10,357.0	18,100.0	282.0	731.0
McMoran Exploration Co.	97.4	295.5	(60.6)	36.4
Meridian Resource Corp.	22.1	38.5	(61.0)	3.6
Murphy Oil Corp.	3,445.6	6,509.5	171.1	409.0
Newfield Exploration Co.	262.0	515.0	(694.0)	(64.0)
Noble Energy Inc.	441.0	1,025.0	(188.0)	215.0
Occidental Petroleum Corp.	3,103.0	6,074.0	377.0	1,875.0
Parallel Petroleum Corp.	18.2	43.9	(20.4)	(2.7)
Penn Virginia Corp.	199.2	249.1	(3.6)	23.2
Petrohawk Energy Corp.	263.5	214.9	(1,000.0)	(55.6)
PetroQuest Energy Inc.	59.5	76.6	(65.7)	15.4
Pioneer Natural Resources Co.	484.2	585.2	(108.8)	128.7
Plains Exploration & Production Co.	228.5	623.1	5.2	163.5
Questar Corp.	923.5	1,002.5	67.7	188.2
Quicksilver Resources Inc.	185.9	157.6	(567.3)	41.6
Range Resources Corp.	276.4	205.3	32.6	1.7
Southwestern Energy Co.	540.8	524.1	(432.8)	109.0
Stone Energy Corp.	132.5	208.1	(357.7)	94.4
Sunoco Inc.	6,441.0	12,813.0	12.0	(59.0)
Swift Energy Co.	76.4	199.0	(59.1)	48.4
Tesoro Corp.	3,280.0	6,606.0	51.0	(82.0)
Valero Energy Corp.	13,824.0	27,945.0	309.0	261.0
W&T Offshore Inc.	117.4	356.5	(230.7)	79.8
Warren Resources Inc.	12.4	23.9	(6.6)	9.5
Whiting Petroleum Corp.	163.8	264.1	(43.8)	62.3
Williams Cos. Inc.	2,128.0	3,204.0	(172.0)	500.0
XTO Energy Inc.	2,161.0	1,673.0	486.0	465.0
Total	**142,465.8**	**307,019.6**	**(9,494.3)**	**29,953.2**

*Third quarter.

Excluding the impacts of entitlement volumes, OPEC quota effects and divestments, production climbed 2% during the recent quarter from a year earlier.

ExxonMobil's downstream earnings were $1.133 billion, down $33 million from first quarter 2008, and its chemical earnings of $350 million were $678 million lower than first quarter 2008.

Marathon Oil Corp. reported first quarter 2009 net income of $282 million, down from $731 million in first quarter 2008. E&P income was $100 million in this year's first quarter, down from $684 million a year earlier on lower oil and gas prices realizations.

Marathon's oil sands mining segment reported a $24 million loss for the recent quarter, compared with earnings of $27 million a year earlier. This was primarily driven by a 57% decrease in average realizations, although synthetic crude sales volumes increased slightly and operating expenses, primarily those driven by commodity prices, were down, the company said.

Meanwhile, Marathon's refining, marketing, and transportation segment income was $159 million in the first quarter compared with a loss of $75 million in first quarter 2008. The increase was primarily the result of a higher refining and wholesale marketing gross margin, which increased to 7.92¢/gal in the first quarter from –0.26¢/gal in first quarter 2008.

Refiners

Houston-based Frontier Oil Corp. was among the refining and marketing companies that posted improved earnings from the first quarter of last year despite a decline in revenues.

Frontier's quarterly revenues were down 29% year-on-year to $846 million. Due to lower costs, the company's net income in the recent quarter was $73.5 million, up 60% from a year earlier.

Valero Energy Corp. and Holly Corp. also reported higher earnings on lower revenues. Valero's net income increased 18% to $309 million, mainly due to higher refining margins on gasoline, fuel oil, asphalt, and petroleum coke. Also, refining operating expenses were down primarily due to lower energy costs.

Partially offsetting the increase in first quarter results was a decline in sour crude discounts and lower diesel and jet-fuel margins. Throughput volumes also declined due to downtime at certain refineries, Valero reported.

Holly's earnings jumped to $23.9 million in the recent quarter from $9.5 million in first quarter 2008. Meanwhile, Sunoco Inc. and Tesoro Inc. each swung to a profit for the first 3 months of 2009 from a loss in the year-earlier period.

Canadian companies

A group of 13 oil and gas producers and pipeline companies headquartered in Canada reported a collective 46% decline in net income for the first quarter of this year. Five of these firms incurred a loss, while two improved on their earnings from a year earlier.

EnCana Corp. reported its first-quarter net earnings increased 934% primarily due to an aftertax unrealized mark-to-market hedging gain, compared with an after-tax loss in the first quarter of 2008. The Calgary-based company's operating earnings declined 9% from the first 3 months of last year, while revenues were down 15%.

Lower price realizations were partly what sunk the quarterly results of Suncor Energy Inc. The company incurred a $189 million (Can.) loss for the first quarter, compared with $708 million (Can.) in earnings in the first quarter of last year. Revenues declined 20% to $4.8 billion (Can.). Mitigating some of the loss were improved downstream margins and lower oil sands royalty expenses.

Suncor said that excluding unrealized foreign exchange impacts on the company's US dollar denominated long-term debt, mark-to-market accounting losses on commodity derivatives, and costs related to start-up or deferral of projects, first quarter 2009 earnings were $227 million vs. $805 million in first quarter 2008.

Canadian oil and gas firms' first quarter 2009 revenues, earnings

Table 2

	Revenues		Net income	
	1st quarter			
	2009	2008	2009	2008
	Million $ (Can.)			
Canadian Natural Resources Ltd.	2,186.0	3,967.0	305.0	727.0
Enbridge Inc.	3,782.6	3,967.8	559.8	253.0
EnCana Corp.	5,777.3	6,812.9	1,206.1	116.6
Crew Energy Inc.	41.1	35.5	(9.0)	0.9
Husky Energy Inc.	3,650.0	5,086.0	328.0	888.0
Imperial Oil Ltd.	4,670.0	7,263.0	289.0	681.0
Ivanhoe Energy Inc.	10,005.0	14,003.2	–15.4	–10.7
Nexen Inc.	1,305.0	2,092.0	135.0	630.0
Penn West Energy Trust	515.0	982.0	(98.0)	78.0
Petro-Canada	3,971.0	6,586.0	(47.0)	1,076.0
Suncor Energy Inc.	4,814.0	5,988.0	(189.0)	708.0
Talisman Energy Inc.	1,576.0	2,000.0	455.0	466.0
TransCanada Corp.	2,380.0	2,133.0	334.0	449.0
Total	**44,673.0**	**60,916.5**	**3,253.5**	**6,062.8**

Service-supply companies' first quarter 2009 revenues, earnings

Table 3

	Revenues		Net income	
	1st quarter			
	2009	2008	2009	2008
	Million $ (US)			
Baker Hughes Inc.	2,668.0	2,670.0	195.0	395.0
BJ Services Co.*	1,054.6	1,283.2	43.0	127.3
Cameron International Corp.	1,257.0	1,339.3	114.6	123.0
Core Laboratories	178.9	179.4	29.2	26.9
Deep Down Inc.	7.1	6.3	(0.7)	(0.1)
Diamond Offshore Drilling Inc.	886.3	790.5	348.6	290.5
Foster Wheeler Ltd.	1,267.2	1,806.3	74.4	138.5
Global Industries Ltd.	270.0	308.2	19.0	26.1
Halliburton Co.	3,909.0	4,049.0	380.0	587.0
Helmerich & Payne Inc.*	522.5	474.9	103.7	102.1
Hornbeck Offshore Services Inc.	109.8	98.5	27.1	22.6
Nabors Industries Inc.	1,142.8	1,321.6	125.2	212.0
Noble Corp.	896.2	861.4	414.3	384.2
Oceaneering International Inc.	435.2	435.9	44.3	41.3
Parker Drilling Co.	174.2	173.6	2.1	23.2
Patterson-UTI Energy Inc.	296.1	504.9	16.2	77.4
Pride International	549.3	540.1	158.9	240.0
Rowan Companies Inc.	495.1	488.7	131.7	98.6
RPC Inc.	176.3	197.2	4.5	14.8
Schlumberger Ltd.	6,000.0	6,289.9	940.4	1,344.7
Smith International Inc.	2,411.5	2,371.0	144.2	246.1
Superior Energy Services Inc.	437.1	441.4	56.8	99.5
Total	**25,144.2**	**26,631.3**	**3,372.5**	**4,620.7**

*Second quarter.

Service, suppliers

A sample of oil and gas service and supply companies recorded a collective 27% decline in first-quarter earnings from a year earlier. The group's combined revenues were down nearly 6%.

In this group of 22 firms, only one incurred a loss for this year's first quarter. Seven of the companies improved on their positive first-quarter 2008 net income, while 14 posted a decline in earnings from a year earlier.

Baker Hughes Inc. reported a 51% earnings decline to $195 million from first quarter 2008, as the company's revenues were little changed at $2.668 billion.

Chad C. Deaton, Baker Hughes chairman, president, and chief executive officer, said, "Our first-quarter results for North America reflect the severe contraction in customer spending and activity. Profit from North America operations was impacted by significantly lower activity levels, severance charges, and price deterioration.

"Results from operations outside North America reflected the relative strength of international markets as contraction in the Saudi Arabia, Russia, Caspian, and UK markets was partially offset by strength in the Latin America, Norway, and Africa markets. Profitability was also impacted negatively by changes in foreign exchange rates and charges related to severance and allowances for doubtful accounts," Deaton said.

Diamond Offshore Drilling Inc. posted one of the largest first-quarter earnings gains in the group, with $348.6 million in net income. This was up 20% from a year earlier, as the driller's revenues climbed 12%.

Contract drilling revenue for Diamond Offshore's rigs, including high-specification floaters, intermediate semisubmersibles, and jack ups, climbed 11% from the first 3 months of last year. Day rates were higher from a year earlier, but utilization declined for Diamond Offshore's high-specification floaters and jack ups. Utilization of the companies' intermediate semisubmersibles was steady from a year earlier at 85%. ✦

US House committee approves climate change bill

Nick Snow
Washington Editor

The oil and gas industry joined other industries that responded critically after the US House Energy and Commerce Committee approved a bill May 21 to address global climate change by instituting a cap-and-trade system.

The committee beat the Memorial Day holiday weekend deadline that Chairman Henry A. Waxman (D-Calif.) set by 1 day when it approved HR 2454 by 33 to 25 votes.

"This bill, when enacted into law this year, will break our dependence on foreign oil, make our nation the world leader in clean energy jobs and technology, and cut global warming pollution," Waxman said following the vote.

The bill's cosponsor, Edward J. Markey (D-Mass.), described the bill as "bold action to preserve good-paying jobs here in American and preserve our planet." Markey is chairman of the committee's Energy and Environment Subcommittee.

Markey said he believes more was accomplished in 8 weeks toward energy independence than the US has accomplished in 8 years.

But HR 2454 immediately drew fire from leading oil and gas associations.

American Petroleum Institute Pres. Jack N. Gerard said, "While the bill has laudable environmental and economic goals, its inequitable system of allocations remains intact and, if enacted, would have a disproportionate adverse impact on consumers, businesses, and producers of gasoline, diesel fuel, jet fuel, crude oil, and natural gas."

National Petrochemical & Refiners Association Pres. Charles T. Drevna said, "While this may appear, in the short term, to be a monumental political success, ultimately it represents nothing more than an abject policy failure. The whole notion of capping carbon dioxide emissions, issuing allowances disproportionately to favored industries, and hoping that the false promise of 'green jobs' could gloss over the current and real jobs that will be lost should HR 2454 become law belies the complexity of fairly balancing energy and environmental policy."

The whole notion of capping carbon dioxide emissions, issuing allowances disproportionately to favored industries, and hoping that the false promise of 'green jobs' could gloss over the current and real jobs that will be lost should HR 2454 become law belies the complexity of fairly balancing energy and environmental policy."
—NPRA Pres. Charles T. Drevna

'Neither wanted nor needed'

"The role of the federal government is not to choose winners and losers in the business sector," Drevna said. "Such policies, with the back of a hand, cast aside millions of hard-working Americans with the simple message that they and their livelihoods are neither wanted nor needed. Such policies fail consumers by effectively limiting individual preference and choice for vehicle and fuel type."

Waxman delayed marking up the bill, called the American Clean Energy and Security Act, by a week so changes could be made from its original version to secure enough votes for its passage. One of the most crucial changes came when Rick Boucher (D-Va.), chairman of the committee's Communications, Technology, and the Internet Subcommittee, announced that he had reached an agreement with Waxman and Markey to preserve coal-related jobs, facilitate more coal production, and keep electricity rates affordable in his southwestern Virginia district and elsewhere where power comes from coal-fired plants.

"It is now inevitable that federal controls on greenhouse gases will be adopted," Boucher said as the bill's markup began on May 18.

"The [US] Supreme Court ended the debate on whether there would be controls when it effectively mandated 3 years ago that the [US] Environmental Protection Agency regulate greenhouse gas emissions unless the Congress regulates first," Boucher said. "Virtually all interested parties, from the coal industry and electric utilities to the environmental community, would prefer that Congress adopt the regulations rather than have them be adopted by EPA."

Chief executives of some of the biggest US power companies have said that action to address global climate change now is essential.

"I understand the arguments against action on energy and climate with concerns focused on the economy," Duke Energy Corp. Chief Executive James E. Rogers told the US Senate Foreign Relations Committee on May 19.

"However, the reality is we can't afford not to act if we hope to compete and lead," Rogers said. "The right comprehensive energy and carbon legislation can provide not only the certainty and rules of the road by which we can plan, build, and compete; it will also protect consumers, help us advance efficiency and

"The right comprehensive energy and carbon legislation can provide not only the certainty and rules of the road by which we can plan, build, and compete; it will also protect consumers, help us advance efficiency and alternative technology efforts, and all while cleaning up the environment."
—Duke Energy Corp. Chief Executive James E. Rogers

WATCHING GOVERNMENT

Nick Snow, Washington Editor

Blog at www.ogjonline.com

Remembering a forgotten fuel

Their timing was good. Earlier that day, US President Barack H. Obama announced more stringent motor fuel efficiency standards. So the automobile and diesel engine manufacturers at the Diesel Technology Forum's late afternoon reception on May 19 were feeling optimistic.

"People are warming up to the idea that no single technology is going to solve the climate challenge. The economic slowdown is also making them conserve, and diesel fuel fits the bill. The engine is very clean and efficient. It does not require new infrastructure. Diesel is already sold at 42% of the nation's gasoline stations," explained Allen R. Schaeffer, the forum's executive director.

"People could start looking at it now with a sharper eye. It's here and available, plus it can use biofuels. The diesel engine, with some renewable components, can be close to the front of the pack," he told me during the group's Capitol Hill reception.

In congressional hearings, however, it's usually overlooked. The ethanol lobby is stronger. Diesel is mentioned only as biodiesel. When federal lawmakers discuss alternatives to gasoline, diesel is largely a forgotten fuel.

Beyond prices

Occasionally, a savvy energy policymaker will take a closer look. Several US House members stopped by the reception. Senate Energy and Natural Resources Committee Chairman Jeff Bingaman (D-NM) used a Sept. 23 hearing on high diesel prices to consider benefits and issues associated with using the fuel more domestically.

The US Federal Trade Commission, in a May 2, 2007, gasoline column on its web site, said ultralow-sulfur diesel's potential benefits are substantial: "greater mileage, less pollution, better cars, and health benefits on top," concluding, "Maybe a diesel car is in your future."

More than 2 years later, representatives from Audi, BMW, Mercedes, and Volkswagen were at the Cannon House Office Building inviting people to test-drive their diesel passenger vehicles. "We're happy to see them. They've become the face of the business in the US," said Matti Kylamarkula, Neste Oil vice-president, US operations.

'100% sure'

"I'm 100% sure that US consumers will need diesel cars. The alternative as the government attacks global climate change is smaller vehicles, which Americans aren't ready to accept," Kylamarkula told me. Neste already produces a renewable diesel using palm, flax, and other vegetable oils and is building additional refineries in Rotterdam and Singapore, where it could help supply the US, particularly the West Coast.

Diesel already is the dominant US trucking fuel. Domestic engine manufacturers' smallest on-highway models are for three-quarter-ton and one-ton pickup trucks, according to Jeff D. Jones, vice-president for sales and market communications at Cummins Inc. "We're aiming it at work vehicles, where diesel's advantages are greater. The tougher the duty, the better it works in terms of fuel economy, performance, and durability," Jones told me. ✦

alternative technology efforts, and all while cleaning up the environment."

'Gasoline prices above $4/gal'

The problem is that HR 2454 doesn't fit Rogers's description, oil and gas industry leaders maintained.

API's Gerard said, "As a recent independent analysis shows, this inequitable approach, by itself, will produce additional unemployment, driving annual job destruction totals related to the legislation to more than 1 million. Another independent study projects job losses more than double this: up to 2.7 million net jobs lost annually, even with new green jobs created. According to one of these reports, an average family will pay an additional $1,500/year for energy and 74% more for gasoline. Today, that would mean gasoline prices above $4/gal, an increase nearly equivalent to a ten rise in the federal gasoline tax."

The bill also would compromise the ability of US refiners to compete with overseas oil product processors, Drevna indicated.

"Imports of refined products, not simply crude, could actually increase under HR 2454, thus impeding national energy security," Drevna said. "American refiners, who already face stiff foreign competition in the fuels markets, would be severely disadvantaged with higher compliance costs under the Waxman-Markey scheme. Foreign refiners, whose facility emissions are obviously not addressed in HR 2454 and whose operating costs are much lower, would gain a distinct advantage over American businesses in the marketplace."

But the American Gas Association, which represents natural gas utilities, said the Energy and Commerce Committee took an important step when it passed the Waxman-Markey bill. The bill allocates emission allowances to local distribution companies to cover the carbon emissions of their residential, commercial, and small industrial customers, it noted. Gas utilities' residential and commercial customers would not be

covered by the bill's carbon cap until 2016, it said.

In a fact sheet that it distributed following the vote, NPRA pointed out that US refiners must meet the earliest compliance mandate for fuels in 2013, while other sources would not be phased in until 2014. "Compared to other industries, domestic refiners receive a disproportionately low number of emissions allowances to meet HR 2454's requirements: just 2% to cover nearly half of the total US carbon dioxide emissions as covered in the bill," it said.

"Assuming a conservative carbon price of $26/ton with 2% of the emissions allowances, a domestic refinery with 100,000 b/d of capacity would have to spend roughly $330 million annually if it were required to purchase emissions allowances for the fuels it produced. Aggregated, these costs would total roughly $58 billion/year for the American refining community and escalate over time as the cost of the program increases," NPRA continued.

Ability to compete worldwide

The American Chemistry Council said that, while committee members made a number of positive changes in the bill, several key issues related to US energy-intensive manufacturers' ability to compete globally still need to be addressed.

"Specifically, we are very concerned that the emissions allocation provision for trade-vulnerable industries (Title VII, Section 782) treats energy-intensive industries differently from other US sectors," Cal Dooley, the group's president, said.

"The bill assigns a baseline year of 2005 for energy-intensives versus a flexible, multiyear base period for other sectors," Dooley said. "The year 2005 was a low-emission one for the chemical industry due to hurricane-related production disruptions, and the designation puts chemical makers at a disadvantage despite the significant greenhouse gas emissions reductions the industry has achieved over the past 2 decades.

"The bill also employs a different emission allowance schedule for energy-intensive industries as compared with other sectors, reducing allowances over time and unfairly depriving energy-intensive manufacturers of receiving more than 200 million allowances through 2021 at an estimated cost of more than $5 billion."

"Assuming a conservative carbon price of $26/ton with 2% of the emissions allowances, a domestic refinery with 100,000 b/d of capacity would have to spend roughly $330 million annually if it were required to purchase emissions allowances for the fuels it produced. Aggregated, these costs would total roughly $58 billion/year for the American refining community and escalate over time as the cost of the program increases."

—National Petrochemical & Refiners Association

While the committee's vote on the bill largely followed party lines, not every Democrat supported it. Charlie Melancon (La.) said that he fully backed many of its aspects but still voted against it because of concerns about its potential impacts on Louisiana's energy workers and industries.

"South Louisianians want to reduce pollution in the air we breathe and the water we drink," Melancon said. "We want to slow or even reverse climate change. And we want our nation to become more energy-independent. But we must do so in a way that won't threaten our offshore oil and gas industry, an industry that has provided good-paying jobs to hundreds of thousands of workers in South Louisiana for generations."

API's Gerard said, "There is time to get this right. As the bill moves to the full House, we ask lawmakers to look at all the consequences of the bill, consider the implications on ordinary Americans at a time of economic hardship, and come up with an equitable plan that will address global climate change and improve, not weaken, our nation's energy and economic security." ✦

EIA global outlook sees more use of unconventional sources

Nick Snow
Washington Editor

Unconventional sources including biofuels could provide nearly half of the growth in global liquid fuel supplies during 2006-30, the US Energy Information Administration said on May 27 in its latest International Energy Outlook.

The forecast's base reference case, which does not assume any changes from current policies, said worldwide demand for liquids and other forms of petroleum could rise from 85 million b/d in 2006 to 91 million b/d in 2015 and to 107 million b/d in 2030.

"Only in the transportation sector are liquids relatively unaffected by the projected high world oil prices," EIA said. "Although world oil prices in 2030 in the IEO 2009 reference case [$130/bbl] are 80% higher than projected in IEO 2008, liquids consumption in the world transportation sector is only 9% lower in this year's outlook."

The forecast's base reference case expects unconventional resources (including oil sands, extraheavy oil, biofuels, coal-to-liquids, and gas-to-liquids fuels) to become increasingly competitive. Their global production, which was only 3.1 million b/d in 2006, increases to 13.4 million b/d in 2030

and accounts for 13% of the world's total liquids supply.

"The increase in production from unconventional resources is almost as large as the increase for conventional supplies," said Howard K. Gruenspecht, acting EIA administrator, during a presentation of the forecast at the Center for Strategic and International Studies. Liquids production from conventional resources climbs 22 million b/d from 84.6 million b/d in 2006 to 106.6 million b/d in 2030 under the forecast's base case.

Variety of forces

Gruenspecht repeatedly emphasized that the actual changes in demand and prices can be influenced by a wide range of forces including changes in governmental policies. "Even over the long term, it's important to remember that prices can vary dramatically because of a wide variety of factors," he said. The latest IEO also uses cases where oil prices reach $200/bbl and $50/bbl in 2030. It also includes two economic growth scenarios, one where global gross domestic product increases 2.4-2.5%/year and another with less yearly economic growth.

Biofuels and Canadian oil sands accounted for 78% of the increase in total unconventional liquids production in the base case. Biofuels production jumps from 800,000 b/d in 2006 to 5.8 million b/d in 2030. Oil sands-bitumen production climbs from 1.2 million b/d to 4.2 million b/d during the same period, while extraheavy oil production grows from 600,000 b/d to 1.2 million b/d and coal-to-liquids production increase from 200,000 b/d to 1.2 million b/d.

"Recent analyses suggest that the recovery act legislation early this year, which was not included in our forecast model, will increase the use of renewable energy sources in the US. Wind power could almost double. We certainly don't believe that fossil fuels are done, but renewables are the fastest growing segment," said Gruenspecht.

The forecast's base case predicted a 49-tcf increase in worldwide natural gas consumption from 104 tcf in 2006 to 153 tcf in 2030. "To meet the projected growth in demand for gas, the world's producers will need to increase annual production in 2030 to a level that is 49 tcf higher than the 2006 level," it said. Much of the additional production could come from countries outside the Organization for Economic Cooperation and Development, it added.

Within the OECD, where IEA expects gas production to climb 7.8 tcf from 2006 to 2030, the largest increase in a single country, 5.3 tcf, is predicted for the US. "Unconventional natural gas production is the largest contributor to growth in US production, as rising prices and improvements in drilling technology provide the economic incentives necessary for exploitation of more costly resources," the forecast said.

Hydraulic fracturing

Unconventional gas production from both tight sand and shale formations could increase from 47% of the US total in 2006 to 56% in 2030, it continued. "There's no question that the gas growth we see in the US from tight sands and shale depends on hydraulic fracturing. If that's taken off the table, the impact would be profound," Gruenspecht said.

The forecast also projected that carbon dioxide emissions worldwide could climb 39% to 40.4 million tonnes in 2030 from 29 million tonnes in 2006. "With strong economic growth and continued heavy reliance on fossil fuels expected for most of the non-OECD economies, most of the increase in [CO_2] emissions is projected to occur among the developing, non-OECD nations," it said.

Gruenspecht said that while government actions to address global climate change could significantly affect prices and production, it's far from certain that India and China, where some of the biggest increases in demand are expected, would be willing to adopt policies that have been proposed in the US.

"The large expected productivity gains in China and India are good news for the people living in those countries. They also pose implications for world markets," he indicated.

"Key energy market uncertainties as well as policy decisions can influence demand. That's why it's important not to base policies on a single reference case," said Gruenspecht. ✦

WoodMac: No gas price rebound seen in near term

Marilyn Radler
Senior Editor-Economics

Weakness in global natural gas markets will delay a recovery in US gas prices and rig counts. Exacerbating the weakness in gas demand has been a marked downturn in demand for electric power by both industrial and residential customers, analysts with the research and consulting firm Wood Mackenzie told reporters on May 20.

The economic recession has had a big impact on US natural gas, electric power, and coal markets. The contractions in the economy during fourth quarter 2008 and first quarter 2009 led to a contraction in power demand at a time when gas supply was increasing from successful development of shale gas and from an increase in LNG imports.

Speaking on power markets, George Given, WoodMac's head of global power research, said he expects the global economic recession will last several more quarters.

Industrial electric power loads were down sharply in the first quarter, Given said, and residential demand for power has declined more sharply than expected based on the extent of the contraction in gross domestic product. Given said the current downturn increases the

likelihood that electric power plants will be mothballed and retired to balance supply and demand.

Although gas rigs have been laid down drastically since September 2008 in response to a gas supply overload and the resulting crash in prices, an upswing is not in the offing next year, according to Jen Snyder, principal analyst for North America gas and power research at WoodMac.

Snyder said a gas price recovery will not come from a lower rig count, but a recovery in gas prices instead will result from a recovery in gas demand. There will be a modest upswing in GDP in 2010, she said, but gas demand recovery will lag until 2012. In the meantime, Snyder sees little upside potential for gas prices.

The US gas market faces three key challenges in the short-to-midterm, Snyder noted. The first challenging condition is a combination of low demand and plentiful coal capacity in the electric power market.

Also posing a challenge to the US gas market is LNG, as there is currently a wave of global liquefaction capacity and oversupply in Europe and Asia. Time lags between drilling decisions and supply responses are the third key challenge to the gas market, Snyder said. ✦

Brazilian president urges Petrobras to invest overseas

Eric Watkins
Oil Diplomacy Editor

Brazil's President Luiz Inacio Lula da Silva, on a state visit to Turkey, said his country's state-operated Petroleo Brazileiro SA (Petrobras) should not hesitate to invest in overseas oil and gas projects.

The Brazilian president's remarks came as the country's oil and gas regulator, the Agencia Nacional do Petroleo (ANP), aiming to step up discoveries at home, denied a Petrobras request for extensions on its concessions in the pre-salt layer.

"[Overseas investments] will help the company have more access to sources of oil," Lula said in Turkey, adding, "Gasoline prices, which are already cheap in Brazil, could become even cheaper [with more overseas exploration]."

Underscoring the chances of his country making discoveries, the Brazilian president even said that "God wants Petrobras to find oil."

Petrobras activity

During Lula's visit, Petrobras was expected to sign an exploration deal worked out earlier this year with the Turkish Petroleum Corp. (TPAO), for a 50% stake in Blocks 3920 (Kirklareli) and 3922 (Sinop) in the Black Sea.

The Brazilian firm began oil production activities in Turkey in February 2006, and completed seismic studies in late 2008. Now, it is poised to begin drilling two exploratory wells.

Petrobras expects the Leiv Eriksson rig to arrive in Turkish waters by yearend, with drilling operations set to begin in the Sinop offshore block during the first quarter of 2010.

Petrobras's international director, speaking on the sidelines of a conference in Istanbul, estimated the firm's investments in the Black Sea as totaling $300 million over the next 2 years.

"We are planning investments of $300 million in exploration activities in the Black Sea in 2009 and 2010. This is the cost of the two wells," Zelada said.

Coinciding with Lula's statement about the importance of overseas investments, the ANP said its board had denied Petrobras an extension on subsalt exploration deadlines for Blocks BM-S-8, BM-S-11, and BM-S-21.

Each of the blocks has discovery evaluation plans approved by the ANP under which Petrobras and its partners must drill further wells to evaluate their discoveries. However, Petrobras said that the shortage of drillships on the market means the current deadline is too short for all of the concessions to be evaluated.

ANP said the following deadlines must be kept: BM-S-9 (Carioca well on Nov. 11, 2011 and the Guara well on Dec. 31, 2012); BM-S-10 (the Parati well on May 31, 2011); BM-S-11 (the Tupi well on Dec. 31, 2010); and BM-S-21 (the Caramba well on Dec. 31, 2012).

In the case of BM-S-8, evaluation can take place to 2010 but the ANP has granted two years for drilling a contiguous well.

The ruling means that Petrobras will step up its operations, going so far as to include contracting services abroad, according to Jose Formigli, the company's subsalt exploration director.

The blocks, which lie in 2,000 m of water and as much as an additional 5,000 m under sand, rocks, and salt, include some of the most promising subsalt oil finds, including the Tupi discovery.

Vital presalt layer

Brazil's Mines and Energy Minister Edison Lobao underlined the importance of the presalt layer to Brazil's future by saying that the region's massive oil discoveries would be enough to "secure the country's energy self-sufficiency for another half a century."

For Royal Dutch Shell PLC, Brazil's subsalt oil and gas reserves are a priority but investment in them will depend on the regulatory model to be drawn up by the government, according to Shell Brasil Chief Executive Officer Vasco Dias.

"It's natural that in the face of subsalt discoveries the government gains a bit of time to see whether the current system is the best for the country," Dias told the state news agency.

Dias said that Shell has three subsalt

WATCHING THE WORLD

Eric Watkins, Oil Diplomacy Editor

Blog at www.ogjonline.com

Philippines picks on 'Big Three'

The oil and gas industry seems to have become the whipping boy of choice these days. It's not just environmentalists this time, but the Philippines government and a handful of price activists.

Last week, the Philippines Department of Justice subpoenaed executives of Petron Corp., Chevron Philippines Inc., and Pilipinas Shell Petroleum following a complaint that they violated the Oil Deregulation Law.

The subpoenas followed a complaint filed by Cebu Gov. Gwendolyn Garcia against the so-called 'Big Three' for imposing higher oil prices in her province than in Metro Manila and other areas.

In an interview, Garcia said her office found by "mere comparison" that fuel prices in Cebu are 5-8 pesos higher than those of Metro Manila and Mindanao.

She said the oil firms claimed that prices of their petroleum products are higher in Cebu because of the costs for transportation of their fuel to the provinces—a point she did not accept.

Dubious distinction

"We are getting the dubious distinction of having the highest prices of fuel in this entire country. These clear, inexplicable price discrepancies have affected business, transportation, and everyone in Cebu," Garcia said.

She is not alone in seeking to punish the three oil companies. Indeed, her complaint came just days after another group claimed that the three companies are overpricing.

According to a group called Bagong Alyansang Makabayan (Bayan), Petron, Shell, and Chevron are earning nearly 164 million pesos a day from selling allegedly overpriced petroleum products.

Based on its estimates, Bayan said all petroleum products on the average were overpriced by 5.11 pesos/l.

"Petron is earning 76.64 million pesos every day from overpriced oil. Shell, on the other hand, is earning 59.21 million pesos daily and Chevron, 27.92 million pesos," Bayan said.

Protest rally

The group made the allegation as its members held a protest rally in front of Shell's main office in Makati City to condemn alleged abuses of oil companies and to press for the repeal of—guess what?—the Oil Deregulation Law.

According to the group, the Oil Deregulation Law did not dismantle the oil cartel but even made it stronger because the important regulatory functions of government, such as control on price adjustments, were taken away.

"Additional powers given to the Department of Energy, for instance, will not stop the abuses of the oil companies as long as the policy framework is to let so-called market forces set the fair price of petroleum products," it added.

However, these complaints coincided with a point made by Energy Secretary Angelo Reyes, who said there is a noted upward movement in oil prices abroad..

No one seemed to question the minister's observation. So, why castigate the so-called 'Big Three' for a problem outside of their control? ✦

concessions in Brazil, and it defends current legislation "with minor adjustments."

"I have no reason to believe that the government will take any type of stance that will discourage private companies from investing," he said.

Speeding up investment into the area will depend on the conditions offered, Dias said, noting that there are competing oil projects in Russia, Africa, and other locales around the world.

The Brazilian government, under instructions from Lula, has been considering possible changes to the country's investment laws that could work against the interests of international oil companies due to the ease of discovering oil and gas in the presalt layer.

Lobao, who favors legal changes that would give priority to investment by Petrobras, underlined the ease of discovery in the presalt layer recently.

"Whenever a drill is placed anywhere in the world, there's a chance that nothing will be found," he said. "There's no such risk in subsalt, it's just a matter of launching the hook and catching the fish," the minister said.

Meanwhile, Petrobras gas and energy director Maria das Gracas Foster said the firm will announce the results of studies into how to ship gas extracted from offshore subsalt finds by 2011.

She said that Petrobras had to decide whether to develop projects alone or with partners, adding that its initial idea is to liquefy the gas offshore on a platform. ✦

Cepu oil flow may be delayed, Indonesia lawmakers told

Eric Watkins
Oil Diplomacy Editor

Production of 20,000 b/d of oil from Indonesia's Cepu block, which the government had hoped would play a major role in boosting the country's output, may take longer than expected, lawmakers have been told.

"The facilities have the capacity of 20,000 b/d," said Achmad Luthfi, deputy for planning at state oil and gas regulator BPMigas. "We expect the facilities to begin production in August, but the first production, of course, will not immediately reach 20,000 b/d."

Luthfi told lawmakers during a hearing with the Indonesian House of Representatives Commission VII, which oversees energy and mineral resources, that production from the block is epected to reach production of 20,000 b/d sometime in 2010. Luthfi's statements reflect a change in government views that earlier expressed confidence Cepu block would begin producing 20,000 b/d in 2009—even including the figure in its 2009 state budget.

The government also expected that from December 2009 the block's production would continue to increase from 20,000 b/d until it reached peak output of more than 150,000 b/d.

However, Luthfi said the level of production from Cepu would remain at 20,000 b/d until as late as the third quarter of 2011. "What I have informed you [of] was a reality," said Luthfi in responses to strong criticism from some of the legislators.

ExxonMobil Corp. spokesman Maman Budiman did not give a date as to when the company expects the block to reach its peak production, saying only that this would be "as soon as possible."

Budiman said, "Currently, the main facilities with the production capacity of 165,000 b/d [are] in the process of preparation for the [engineering, procurement, and construction] contract tender."

Cepu block lies on the border of East Java and Central Java and is said to hold proved reserves of 600 million bbl of oil and 1.7 tcf of natural gas.

ExxonMobil subsidiary Mobil Cepu Ltd. and state-owned PT Pertamina each hold a 45% stake in the block, with the remaining 10% controlled by local government administrations. ✦

Gulraiz Akhter
Naseer Ahmed
Zulfiqar Ahmad
Quaid-i-Azam University
Islamabad

An attempt has been made using seismic and well data to predict the possible overpressure zones and pore pressure estimation for the principal reservoir, the Sui Main limestone formation, at Qadirpur, a producing gas field in Pakistan's Central Indus basin.

Seismic, well data used to estimate pore pressure, predict overpressure

First, a synthetic seismogram is generated to mark the geologic horizons. The methodology introduced here is a calculation of sonic drift from seismic and well data, which greatly improved the results by removing anisotropy from the synthetic seismogram by calculating the velocity drift using common depth point and log data.

High pressure zone calculations are made by using log data. The plot between pressure and velocity indicated the velocity drop for the Sui Main limestone, which was indicated as a high pressure zone from seismic data calculations.

For pore pressure, distortion in pressure values is observed along with the main increasing pressure trend. These distortions may be due to the presence of any fluid or other material in the pore spaces.

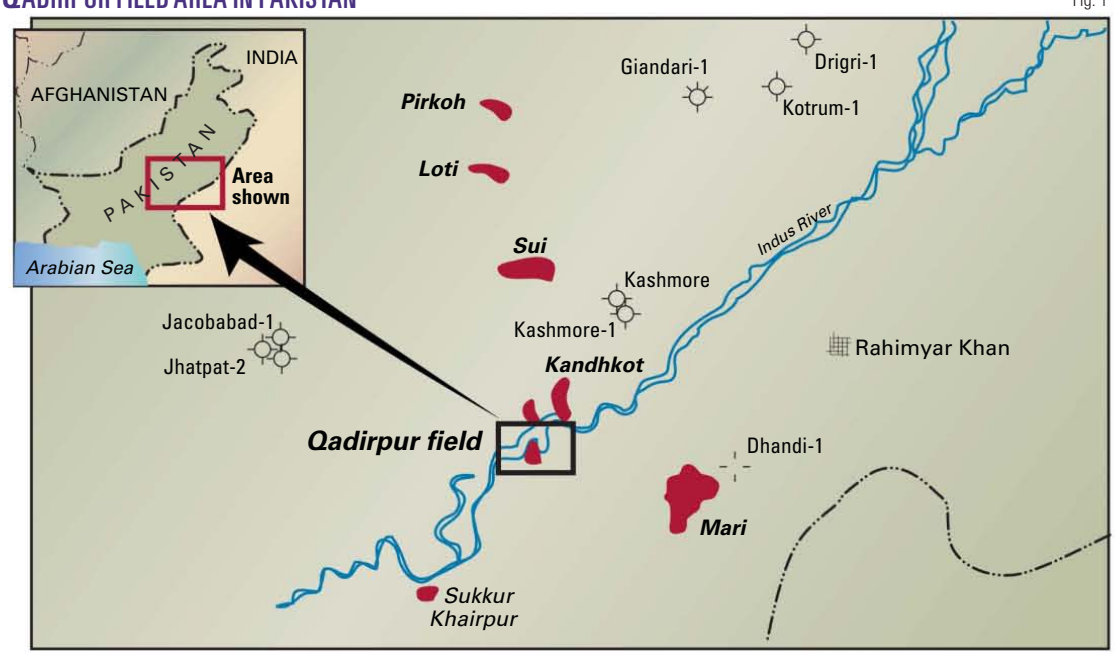
Introduction

Qadirpur administratively lies in the Ghotki and Jacobabad districts of Sindh Province, Pakistan (Fig. 1).

Previously about 420 lines of 2D seismic survey were shot in 1990, 1992, and 1998 by Oil & Gas Development Corp. Ltd., which discovered

QADIRPUR FIELD AREA IN PAKISTAN

Fig. 1



gas in Eocene limestones. A total of 35 wells have been drilled in this area, of which 30 wells are currently producing.

Qadirpur field was developed in three phases, increasing its capacity from the initial 235 MMscfd to 500 MMscfd. The aim of the project in progress is to increase field capacity to 600 MMscfd. Development drilling continues in order to maintain the gas supply to Sui Northern Gas Pipeline Ltd.

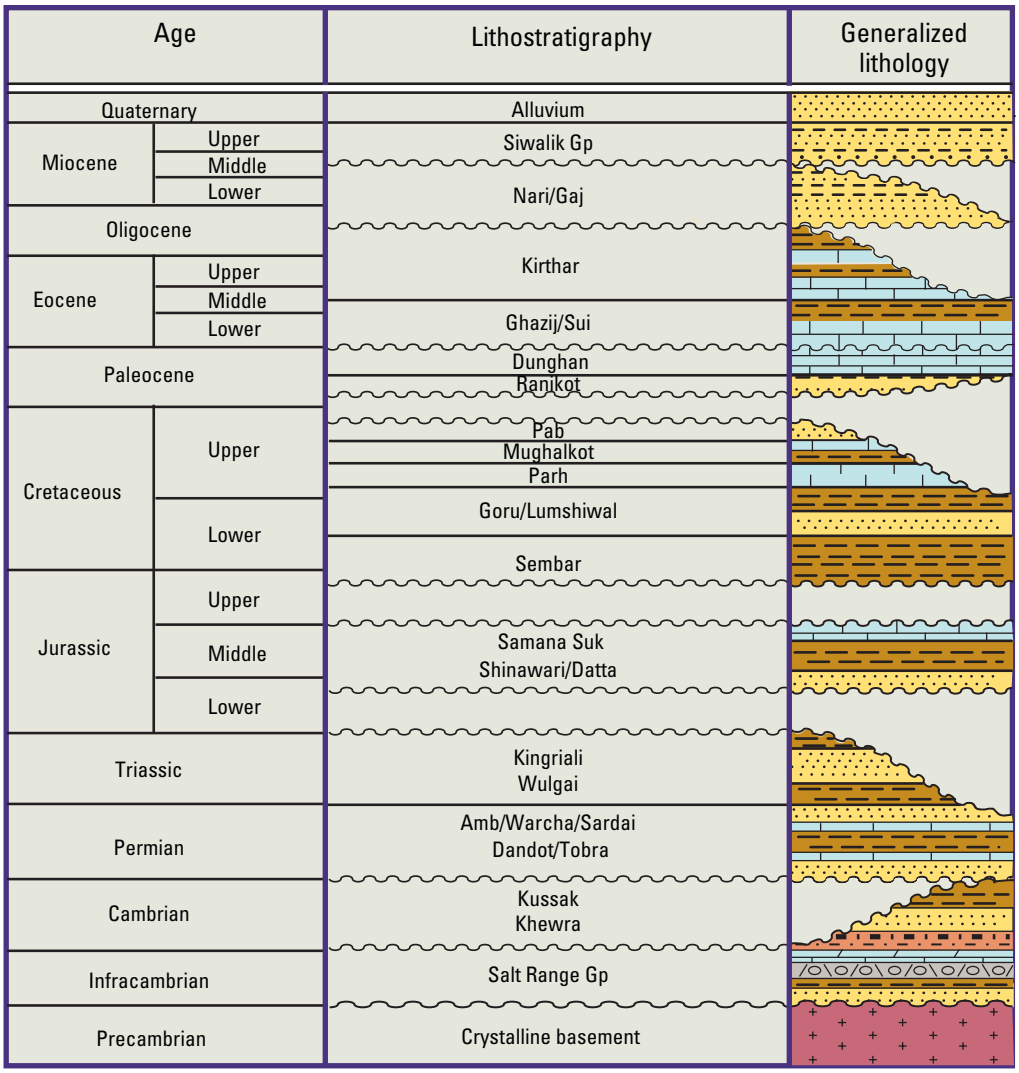
The Lower Eocene Sui Main limestone is the most prolific gas reservoir in Pakistan. In the Kirthar Range of southern Pakistan and the Punjab platform, the Sui Main limestone is the chronostratigraphic equivalent of the Laki formation, a nonreservoir facies.[1]

To date, only gas has been encountered in the Sui Main, which has recoverable reserves of more than 20 tcf in the 14 discovered fields. Sui Main is the main producer of gas in Qadirpur field.[2]

In this study,

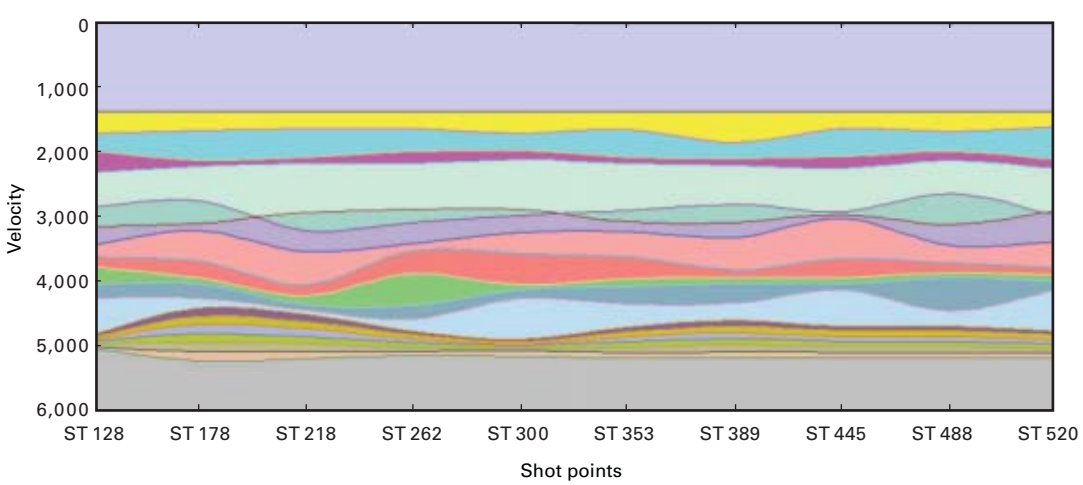
GENERALIZED STRATIGRAPHY, PUNJAB PLATFORM, CENTRAL INDUS BASIN

Fig. 2



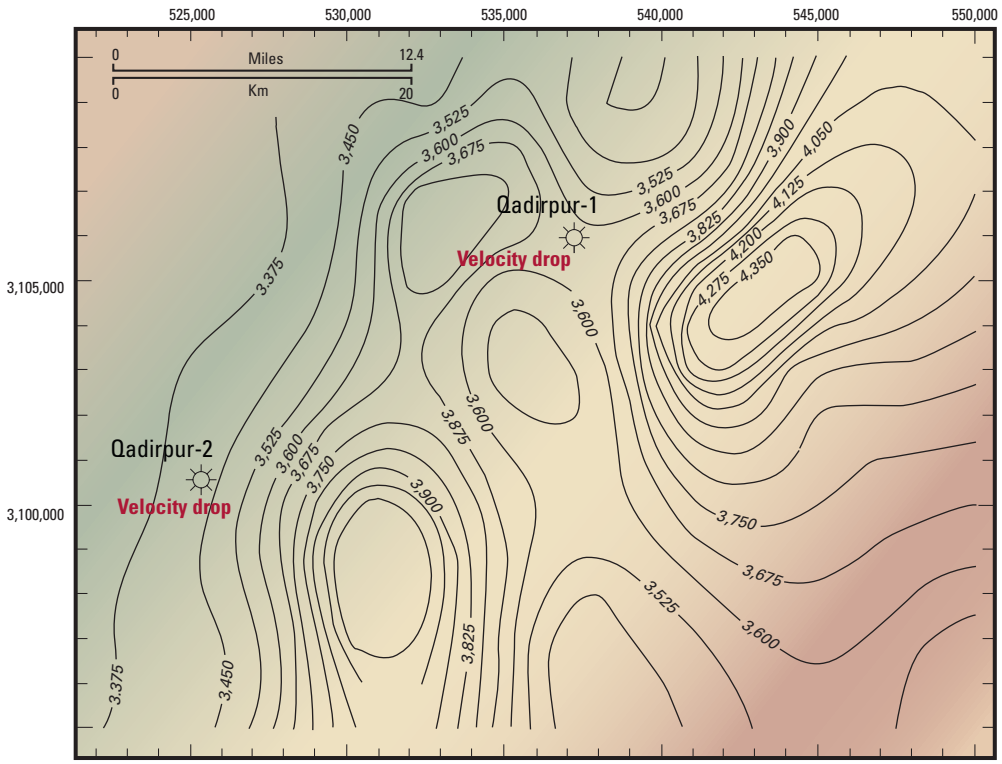
INTERVAL VELOCITY ISOSECTION

Fig. 3



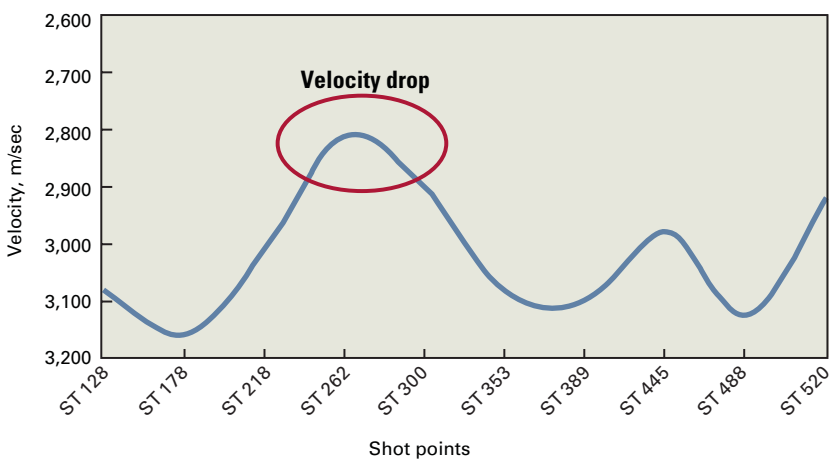
CONTOUR MAP OF INTERVAL VELOCITY, QADIRPUR AREA

Fig. 4



INTERVAL VELOCITY OF SUI MAIN LIMESTONE

Fig. 5



seismic data with sonic and density logs run in Well 2 are used. These logs are used to generate the synthetic seismogram and to estimate pressure[3] as the investigated area is gas prone and pressure related problems often occur in such areas, which led to this study's goal of detecting overpressure zones before drilling, Interval velocities are used from seismic and well data for matching the results for the Sui Main limestone, as introduced by Sheriff.[4]

In this study the approach of sonic drift is introduced which played an important role in removing the anisotropy from well data.

Area geology

Geologically the investigated area is in the Mari Kandhkot high, central Indus basin of Pakistan.

It is bounded on the north by the Sargodha high, Indian shield on the east, marginal zone of the Indian plate on the west, and the Sukhar rift in the south.[2]

The surface is covered by alluvium of the Indus River floodplain. The main potential source rocks are the Sembar shales. The shales of the Mughalkot fomation, the Ranikot formation, and the Sirki formation are also considered for their source potential.[5]

The Sui Main limestone and Sui Upper limestone are the main producer, whereas the limestone of the Habib Rahi formation is considered as a secondary reservoir.[6,7]

The Sui Main is a closed-system reservoir, having a huge common aquifer system with all the known and unknown hydrocarbon fields perched at different hydrostatic levels. Being a closed-system reservoir, the gas pools are expected to experience weak aquifer support during fields' producing lives. This phenomenon has so far been observed in fields that are in a mature stage of production, like Sui field.[1]

Besides Qadirpur, the Sui Main limestone is gas bearing in many Indus basin fields (Fig. 2). Eocene limestones such as Sui Main have good porosity because of their development on a stable platform, while timely gas

entrapment is responsible for the preservation of the porosity. The limestone reservoir in this region has following types of porosities:

- Matrix microporosity.
- Mouldic porosity.
- Vugular porosity.
- Intragranular porosity.
- Intercrystalline porosity.

The most common porosity observed is the matrix microporosity system that is developed by the framework of clay-sized carbonate matrix. Fractures, although present, are not the most important contributors to the development of effective reservoir porosity and permeability in the Sui Main limestone.

In the central Indus basin, the top of the Sui Main limestone (early Eocene) is a characteristic intra-Eocene reflector because of its acoustic contact with the overlying Ghazij shale, which is seismically transparent and devoid of any significant character.[8] The Eocene rocks are represented by heterogeneous lithological assemblage (shales, limestone, evaporite, coal, and minor sandstone) in various basins of Pakistan.

According to Kadri,[6] the main drilling problems in the carbonates are severe loss of drilling fluids in porous/fractured gas bearing reservoirs (Sui Main limestone and Habib Rahi limestone). Special care is required in detecting potential blowouts and avoiding permanent formation damage to the reservoir. Stuck-hole conditions are also experienced where considerably thick Eocene shales are drilled.

Use of seismic data

Detection of overpressure before drilling is more useful as precautions can be taken and planning can be done accordingly.

Reflection seismic methods are commonly used for this purpose and exploit the fact that overpressured intervals have lower velocities and impedances than normally pressured intervals at the same depth. During the exploration phase, pore pressure prediction helps in studying the hydrocarbon trap seals, mapping of hydrocarbon migration pathways, analyzing trap configurations and basin geometry, and providing calibrations for basin modeling.

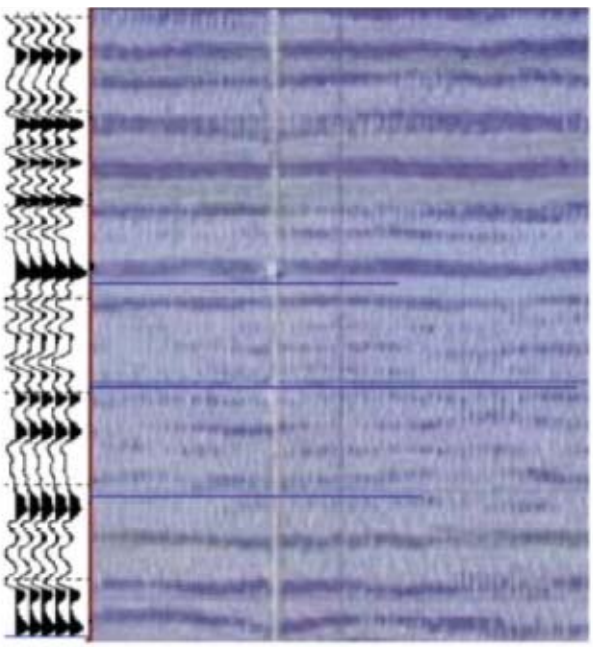
Predrill pore pressure prediction allows for appropriate mud weight to be selected and casing program to be optimized, thereby enabling safe and economic subsurface drilling. The importance of determination of this information has gradually been realized as some major well disasters have led to lives lost and adverse publicity. Besides drilling a well, the only way to predict potential hazards like overpressured subsurface zones is through the use of seismic surveys.[9]

The study involves the application of interval velocities which are important for studying the behavior of rocks and their transit time, porosity, density, pressure, etc. Velocities slow in hydrocarbon zones, including the Sui Main limestone (Fig. 5). The overall behavior of interval velocities for the investigated area and around the well is shown in Figs. 3 and 4.

The zones where velocities drop are hydrocarbon zones, and pressure values rise in these zones for the Sui Main limestone. The estimation of pore pressures from seismic data uses seismically derived velocities to infer the subsurface formation pore pressure. The overpressure zone for the Sui Main limestone is estimated first from seismic data in which we used interval velocities. Interval velocities are used in the form

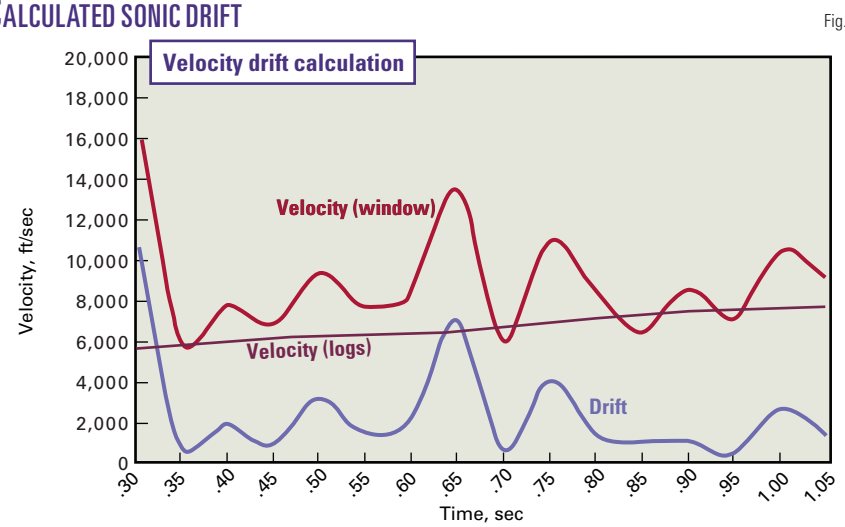
SYNTHETIC SEISMOGRAM BEFORE SONIC DRIFT

Fig. 6



CALCULATED SONIC DRIFT

Fig. 7



of isovelocity section, which indicated different high pressure zones in the form of velocity drop or crest (Fig. 3). To mark the high pressure zones, a well contour map of the interval velocities (Fig. 4) again confirmed the velocity drop in hydrocarbon zone.

Since our target is the Sui Main limestone, an individual interval velocity for that formation is extracted from an isointerval velocity section to observe the velocity changes.

Overpressured formations exhibit several of the following properties when compared with a normally pressured section at the same depth:[10]

1. Higher porosities.
2. Lower bulk densities.
3. Lower effective stresses.
4. Higher temperatures.
5. Lower interval velocities.
6. Higher Poisson's ratios.

Seismic interval velocities are influenced by changes in each of these properties, and this is exhibited in terms of reflection amplitudes in seismic surveys.[9] Consequently, velocity determination is the key to pore pressure prediction.[4]

Use of well data

Changes in pore pressure can be recognized on regular formation evaluation tools such as sonic, resistivity, porosity, and density logs.

These logs show the effects of pore pressure because of the relationship between compaction, porosity, density, and the electrical and acoustic properties of sediments. As a rock compacts, the porosity is reduced and the density increases, which also causes the bulk modulus and shear modulus to rise because of increases in grain contact area and grain contact stress. This process continues until the mechanical process of compaction is slowed by either the stiffness of the rock frame or by increases in pore pressure that resist further compaction.[11]

SYNTHETIC AFTER SONIC DRIFT Fig. 8

In well data sonic and density logs are used for synthetic seismogram to mark the geologic horizons as shown in Fig. 6. The calculated drift is shown in Fig. 7. The main function of sonic drift is to remove the anisotropy from well velocity so that a synthetic seismogram can be generated without anisotropy to mark the geologic horizons.

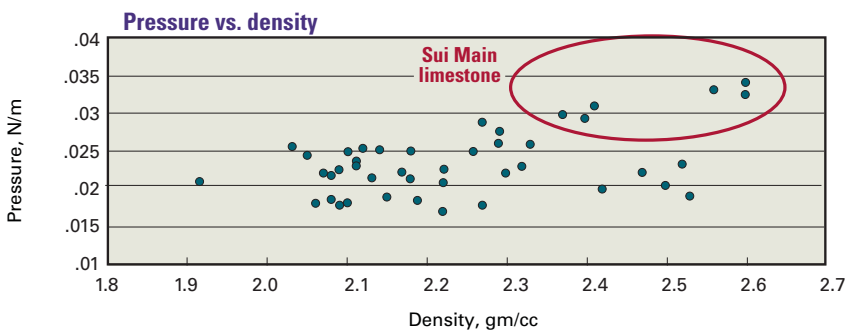
Then the concept of sonic drift is introduced to remove the anisotropy from the velocities. The drift is calculated by using the CDP data and well data by taking the difference between log velocity and seismic velocities. After sonic drift calculations, again a synthetic seismogram is generated, as shown in Fig. 8, that is more precise and accurate than the previous synthetic seismogram.

Overpressure in sedimentary basins has been attributed to different mechanisms, but the main ones are related to increase in stress and in situ fluid generating mechanisms.[12] The ability of each of these processes to generate overpressure depends on the rock and fluid properties of the sedimentary rocks and their rate of change under the normal range of basin conditions like increases in stress, secondary pressure mechanisms, structural uplift, etc.[13]

Changes in pore pressure can be recognized on regular formation evaluation tools such as sonic, resistivity, porosity, and density logs. These logs show the effects of pore pressure because of the relationship between compaction, porosity, density, and the electrical and acoustic properties of sediments.[14]

As a rock compacts, the porosity is reduced and the density increases (Fig. 9), which also causes the bulk modulus and shear modulus to rise because of increases in grain contact area and grain contact stress. In this study, high-pressure zone calculation is made by using log data. After calculating pressure

POROSITY IS REDUCED AS ROCK DENSITY INCREASES Fig. 9



it was plotted against velocity and also against density to observe the pressure variation for the Sui Main limestone. The velocity drop, which was observed by seismic data, is encountered with the same range in well velocity as that of the Sui Main limestone (Fig. 10).

Pore pressure or formation pressure is defined as the pressure acting on the fluids in the pore space of a formation.[15] Also, the sonic velocity, density, and resistivity of a normally pressured formation will generally increase with depth of burial, and the way such rock properties vary with burial under normal pore pressure conditions is termed the normal compaction trend.[16] Pore pressure gradient is defined as the ratio of the formation pressure to the depth and is usually displayed in units of pounds per square inch per foot or Newton meter (N/m) (Fig. 11).

The pore pressure is calculated by plotting pressure against depth. The continuous line (Fig. 11) shows the major increasing trend of the pressure, while the distorted values above and below the line are the indications of some fluid or any other material present there. The pore pressure is calculated by taking the difference above and below the line as shown in the Fig. 11.

Results

The following results are drawn from the calculations discussed.

Interval velocities from seismic data proved to be very informative in delineating the rock properties and pressure zone for the Sui Main limestone. The interval velocity isosection of the whole seismic line indicated the behavior of interval velocity. From this isosection, we can easily understand its behavior by observing its rise and fall.

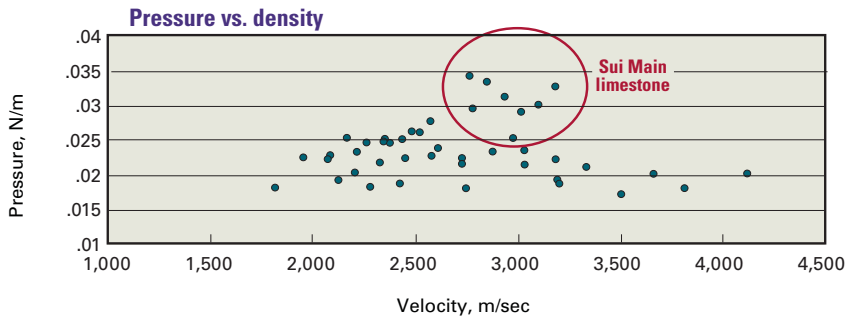
For the Sui Main limestone the individual velocity is extracted, and it shows velocity drop as in Fig. 5. The velocity drop indicated a high pressure trend in the isointerval velocity section, especially for the Sui Main limestone.

The calculation of sonic drift is used to remove the anisotropy from the well velocities. The effect of sonic drift can be seen in synthetic seismograms and in the pressure calculations, which played a vital role in matching the synthetic with original seismic data and to mark the appropriate pressure zones.

The plot of pressure against density and velocity clearly indicated the pressure rise. The density increased in the zone where pressure increases in the Sui Main limestone (Fig. 9). Similarly for pore pressure is calculated in Fig. 11, which shows a major increasing trend for the Sui Main limestone, and the distortion occurs due to the presence of some fluid or any other material in the pore space. ✦

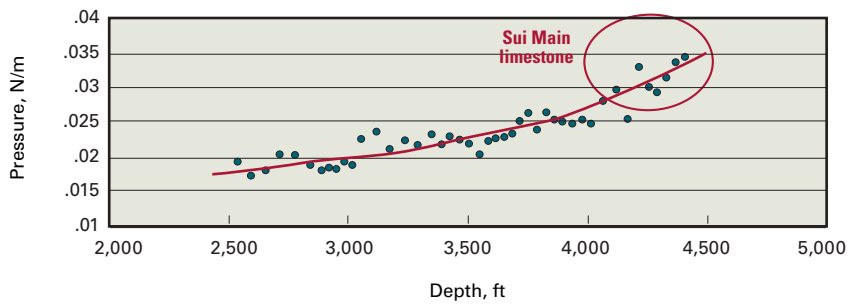
SUI MAIN LIMESTONE PRESSURE VARIATION

Fig. 10



PORE PRESSURE RISES WITH DEPTH

Fig. 11



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Project undertakes deepwater production measurement gaps

Guntis Moritis
Production Editor

A new joint interest research project aims to improve production measurements from deepwater fields.

The Letton-Hall Group, Houston, received a contract from the nonprofit Research Partnership to Secure Energy for America (RPSEA) for the project.

"This project is significant because, if successful, it will clear the way to more affordable, more realistic deepwater production," says Jim Chitwood with RPSEA.

"The current situation in deepwater exploration is that often companies may drill several deepwater wells and commingle their production. Measuring the flow from each well and allocating the oil and gas production is a big issue at those depths," he says.

Jim Hall, cofounder in the Letton-Hall Group, told OGJ that the project came into effect on Nov. 1, 2008, with work starting in February 2009.

REPSA will provide 80% of the $4.5 million budget with the other funding coming from seven initial companies: BHP Billiton Ltd., BP PLC, Chevron Corp., ConocoPhillips, Royal Dutch Shell Group, StatoilHydro, and Total SA. Each company's contribution to the project is $150,000, meaning that the project is currently overfunded by $150,000, Hall said. He also thought some additional companies might also join the project.

The six tasks the project will look at are:

1. Deepwater subsea sampling.
2. Remotely operated vehicle (ROV) assisted subsea flow measurement.
3. High pressure, high-temperature qualification of flow measurements.
4. Flow modeling evaluation.
5. Meter fouling.
6. Metering system uncertainty.

Hall said the deepwater subsea sampling part of the project will last 2½ years, while the other parts are scheduled for completion in 2 years.

The project has signed contracts for the ROV part of the work with Oceaneering International Inc., Houston, and with Multiphase Systems Engineering at the University of Tulsa for evaluating models and metering systems.

Hall noted that DeepStar Project 8302 for improved multiphase metering for subsea tiebacks had identified many of the tasks slated in RPSEA Project DW1301 for improving deepwater measurements. Fig. 1 shows the relationship between the DeepStar and RPSEA projects.

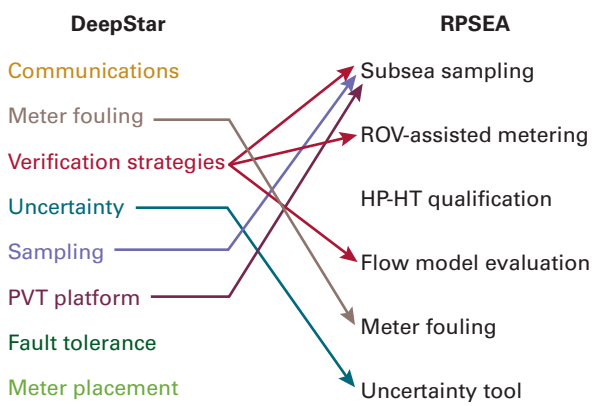
RPSEA's funding comes from the US Energy Policy Act of 2005 that funds natural gas supply research and development programs during 10 years. RPSEA is the consortium selected to manage these funds.

Deepwater subsea sampling

Although the placement of subsea multiphase flowmeters near the well improves reservoir management, well diagnostics, and allocation, the project's scope notes that multiphase flowmeters require timely, accurate fluid properties, at meter conditions and that well tests

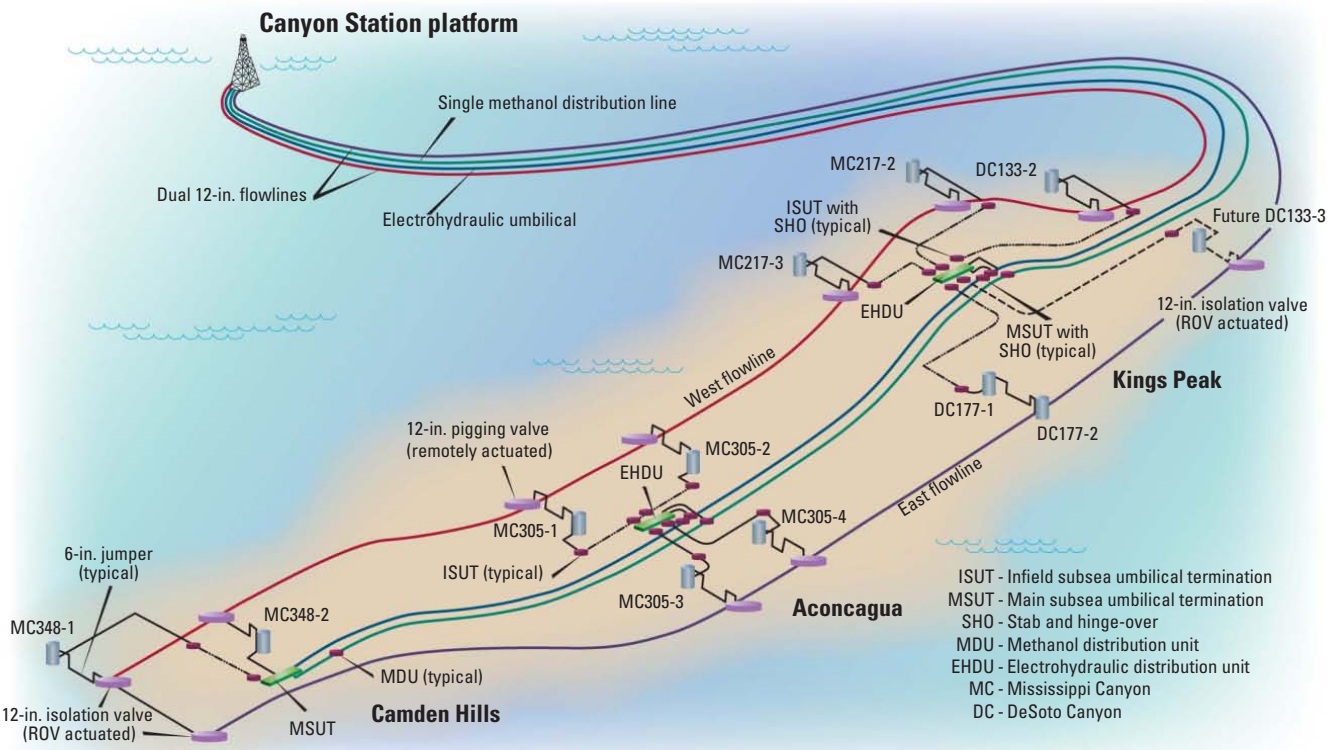
DEEPSTAR INFLUENCE ON RPSEA PROJECT

Fig. 1



CANYON EXPRESS SYSTEM

Fig. 2



Source: Stearns, J., "Canyon Express touts industry firsts, shared infrastructure for deepwater gulf development," OGJ, May 19, 2003, p. 64.

and topside samples cannot meet these needs.

The scope says that sampling at or near the wellhead can provide samples that represent the fluid flowing through the meter, yielding more accurate fluid properties and more accurate multiphase measurements than the current costly and inaccurate methods for determining gas properties via topside samples.

Its plan to develop a method for ROV-deployed subsea sampling will provide a means to capture representative fluid samples at the multiphase meter and other locations at various times throughout the life of the well.

The proposed work will develop a standardized, ROV-deployed sampling system that gathers subsea samples in situ, near the well, resulting in more timely and accurate fluid properties for improved allocation, well monitoring and diagnostics, and reservoir management.

This sampling part of the project will evaluate the potential of existing sample systems and conceptual designs deployed via ROV. The work also includes selection, development, and testing of a candidate system with an ROV, as well as development of draft standards for sampling connections (interfaces), tools, equipment, and operations.

ROV assisted measurement

The project's scope notes that verification of deepwater subsea flowmeters is key to removing risk from both the allocation of revenue among producers and the collection of royalties in US federal waters. It says while the meters may measure multiphase flow from wells when they are first installed, this becomes an increasingly difficult task as fields and equipment age. This drift away from correct operation will lead to incorrect fiscal allocation of revenues and assessment of royalties.

Hall noted that the Canyon Express development in the Gulf of Mexico was an example of the need for this technology. Canyon Express involved production from eight wells in three fields with several owners and differing royalty rates commingled in two flowlines. Each well initially produced gas with small amounts of condensate and, in a few cases, water. The production balance from the two flowlines with topside separator measurements was about 6-8%, but this deteriorated to 15-25% within a few months.[1]

At that point, total production from all wells averaged about 450 MMscfd, so that a 20% imbalance represented 90 MMscfd, or more than $250,000/day at the prevailing 2003 prices of 2003.[1] Fig. 2 shows the fields in 2003 (OGJ, May 19, 2003, p. 64).

The project's scope for this second task is for developing methods to convey measurement equipment to the wellsite where it will be clamped on at a predefined position. It expects that production allocations will improve by making and comparing measurements

from each well contributing to the commingled production.

Hall said that the project currently is not focusing on any technology. He said that a gamma-ray densitometer is a leading candidate because ultrasonic meters currently cannot go underwater.

HP-HT qualification

The project's scope notes that current subsea multiphase and wet-gas flowmeters have a 125° C. temperature and 10,000-psi operating pressure limit. To increase measurement capability to 15,000 psi, Task 3 aims to address these operational restrictions by identifying the sources of the limitations in the most universally used sensors in multiphase and wet-gas flowmeters.

These sensors include those for measuring pressure, temperature, and differential pressure.

The project will assemble and, if required, design and fabricate prototype sensors and then integrate the sensor elements into transmitter housings designed to meet an operational pressure of at least 15,000 psi.

The scope notes that because of the cost required to develop sensors for these applications and the small yearly sales potential of probably fewer than 1,000, a sensor manufacturer would be unlikely to undertake this development without external funding.

Evaluation of flow modeling

The scope notes flow modeling, commercially called virtual flowmeter (VFM) technology, is maturing, but the industry has only a few studies that evaluate the performance and accuracy of commercially available VFM's for subsea systems.

Task 4 will address this gap in studies of current VFM technology. The project plans to evaluate existing VFM by comparing the predictions of the VFM's with actual field data from subsea multiphase flowmeters or other measurement sources.

Its objective is to identify areas of strengths and weaknesses. By documenting where existing VFM's can function within the required error limits, it will establish boundaries on their use. By categorizing the operating regions where existing VFM's need enhancements, this task will provide guidance to future needed developments to extend the operating envelope.

This task will provide the industry with applicable operating conditions for VFMs, enabling more confidence in their use.

Another benefit for the work is probable regulatory authority acceptance of the use of VFM systems, both for verification method of fiscal allocation and as a backup to physical subsea flowmeters.

Meter fouling effects

Field operations show that meters can become fouled or altered by scale, wax, asphaltenes, hydrates, corrosion, and erosion. Task 5 will evaluate these effects on measurement and determine their nature and magnitude.

The project will address gaps in the deployment and use of multiphase and wet-gas metering technology in deepwater production systems, as well as provide insights into ways fouling can alter meter response.

The scope of the tests will evaluate commonly used multiphase meter elements, such as the Venturi and cone, to determine the effect on meter of synthetic deposition such as scale and wax or erosion.

Canyon Express is an example of the importance of fouling because one conclusion from that project was that the presence of scale on the walls of some meters caused incorrect response of the meters, essentially changing their discharge coefficient.[1]

Metering system uncertainty

Task 6 will analyze flow rate measurement uncertainty, which is a key methodology for addressing production allocation, reservoir performance optimization, operational issues, and regulatory reasons.

The scope notes that the industry has no unique procedures for predicting total system uncertainty associated with multiphase flowmeters, well test separator systems, and the pipelines connecting them, especially for commingled flow configurations.

The project will investigate and quantify the uncertainty, both bias and random, associated with meters in two or three-phase flow. In addition, it will determine detailed characterization of multiphase pipeline flow that will involve both the propagation of uncertainty in pressure-volume-temperature (PVT) models to local flow conditions, as well as uncertainties that result from the transient nature of the multiphase flow in the pipe.

Another part of the project will extend the previously developed well test measurement uncertainty analysis to multiphase meters. It will base the extension on the physical principle of the meter and the associated hydrodynamic flow behavior.

From this work, it plans to deliver a software tool with a user friendly interface for predicting total network uncertainties for systems with subsea multiphase flowmeters, accounting for meter operating conditions, in situ PVT properties, system configurations (such as commingled flow), and pipeline uncertainties.

It notes that knowledge of system-wide uncertainty will facilitate verification of meter performance and fair allocation of produced fluids, provide early indication of measurement problems anywhere in the system, and provide all parties (vendors, operators, partners, service companies, and regulatory agencies) a realistic picture of the measurement quality. ✦

Reference

1. Hall, J., et al., "Deepwater Measurement Verification—a DeepStar-RPSEA Mandate," 26th International North Sea Flow Measurement Workshop, Aberdeen, Oct. 21-24, 2008.

Global downturn will narrow 2009-10 margins, utilizations for Asia-Pacific

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The subprime crisis that began in the US continues its domino effect on all sectors, including the oil industry in Asia-Pacific. Slowing economies in the US and Europe reduce the demand for exports from the Asia-Pacific, which in turn reduces manufacturing output, investment, and economic growth in this export-dependent region. Asia-Pacific demand for oil products will decrease by 414,000 b/d in 2009.

The extent and duration of the impact of the credit crisis on oil product demand may differ widely among countries, depending on future economic developments and past and future domestic pricing policies. Despite substantial uncertainty, it is critical to reevaluate the outlook for product demand, trade balances, and refinery utilization.

Hard landing

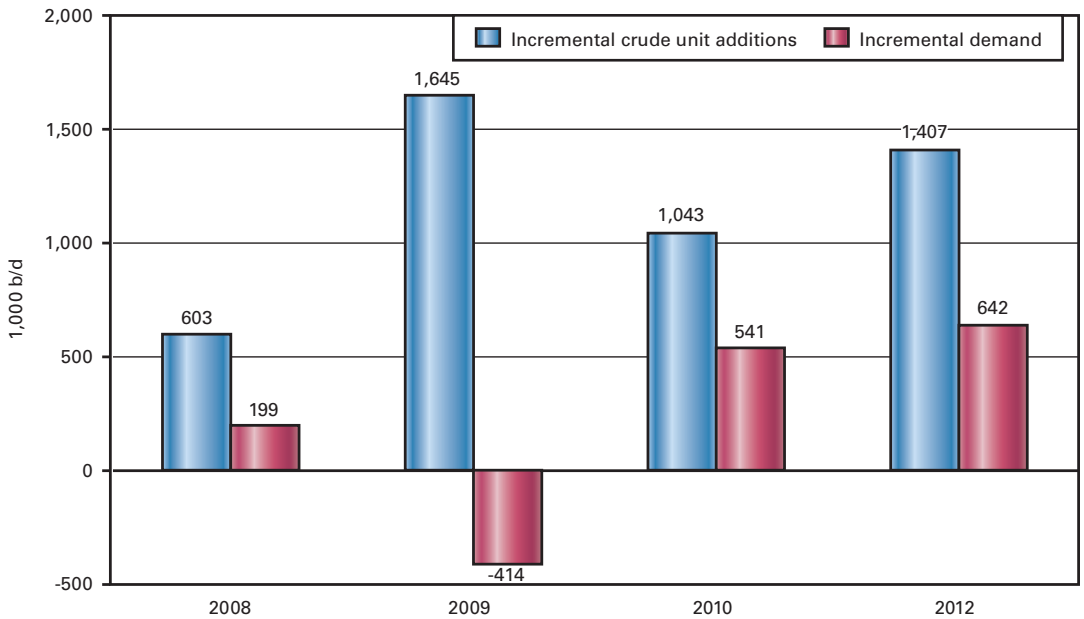
The slowdown in demand growth could not have come at a more inopportune time, with Asia-Pacific adding 2.7 million b/d of refining capacity over 2009-10. Fig. 1 shows there will be 1.6 million b/d of new capacity coming on line in 2009 vs. the decrease of 414,000 b/d in demand. Center stage is the start-up of the new Reliance Petroleum Ltd. refinery, launching 580,000 b/d of new capacity and contributing to more than a third of the refinery addition in 2009.

Start-up of RPL, which was developed as an export refinery, occurs at a time when the window of opportunity for exports to the US and Europe is closing. FACTS Global Energy data show that, in 2008, US oil demand declined by 1.1 million b/d to 19.6 million b/d, pulled down by a decrease in demand for gasoline and diesel. We expect oil demand in the US to continue its slide in 2009, but more slowly. This year, the US could shed an additional 0.5 million b/d. Driven by the crisis, European demand will fall by around 0.4 million b/d in 2009.

With so much new capacity coming on as global demand is decelerating, many refineries in the region will experience a hard landing in terms of refining margins. In 2009, we estimate that the regional cracking margin will decline by around 50% vs. 2008 (i.e., down to around US $3.0/bbl) and further down to

ASIA-PACIFIC DEMAND, DISTILLATION ADDITIONS

Fig. 1



$1.60/bbl in 2010 (Fig. 2).

Refiners will have to make difficult strategic adjustments, including running their refineries at significantly lower throughputs, delaying construction plans, or worse, closing existing refineries. Fig. 3 presents FGE's outlook for average utilization of refineries in the Asia-Pacific. Which path refiners choose much depends on a variety of factors such as domestic demand, import protection, access to credit, and even the timing of refinery upgrades.

Export-oriented refineries will have to bear the brunt of the impact of the downturn in demand because they will be hard-pressed to find a home for their surplus production.

The impact on the domestic refineries, however, varies. Those refineries that are more complex obviously can weather the downturn better than less sophisticated ones. Refineries that just finished (or will complete) upgrades in 2009 will also have the means (and the pressure from the investors) to at least maintain their throughput.

China product balance

Table 1

2009	Ouput	Imports	Exports	Demand
LPG[1]	633	54	15	662
Naphtha[1]	672	33	25	665
Gasoline[2]	1,561	25	81	1,495
Kero/jet	286	99	95	290
Diesel[2]	2,850	30	53	2,842
Fuel oil	474	259	85	648
Other	817	75	45	847
Total	7,292	575	399	7,448
Dubai crude	220	—	—	220

[1]Nonrefinery LPG: — Naphtha: —. [2]Ethanol: 43 Biodiesel: 19.

2010	Output	Imports	Exports	Demand
LPG[1]	679	25	15	689
Naphtha[1]	755	128	20	863
Gasoline[2]	1,669	5	121	1,553
Kero/jet	301	93	90	305
Diesel[2]	3,007	6	48	2,965
Fuel oil	477	207	25	659
Other	839	74	40	873
Total	7,728	538	359	7,907
Dubai crude	223	—	—	223

[1]Nonrefinery LPG: Naphtha. [2]Ethanol: 67 Biodiesel: 32.

Regional variations

The following sections provide a rundown on how refineries in different countries are coping with the surplus refining capacity that is afflicting the region.

Australia

The Australian refining sector continues to face the challenges of changing fuel needs and fierce import competition. As part of regional supply optimization, oil companies in Australia have the option of importing products from elsewhere in the region. In fact, Singapore is already one of Australia's main suppliers of refined products.

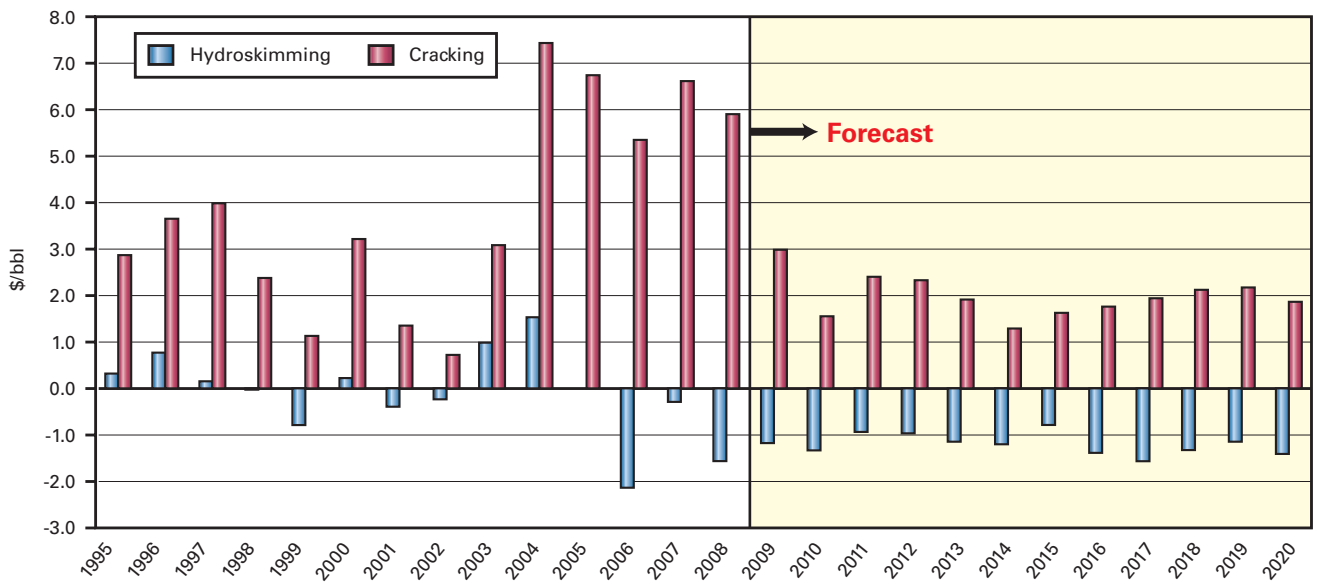
Restructuring of the sector is inevitable if returns are not maintained. We expect utilization to drop to an average 84% in 2009 from 91% from 2001-08.

China

FACTS Global Energy's fall 2008 Databook forecast China's crude runs in 2008 and 2009 at 6.96 million b/d and 7.4 million b/d, respectively. Our latest assessment put 2008 crude runs at more than 6.8 million b/d and 2009 runs at nearly 7.3 million b/d. The respective cuts were 137,000 b/d and

Gross refining margins, Dubai crude*

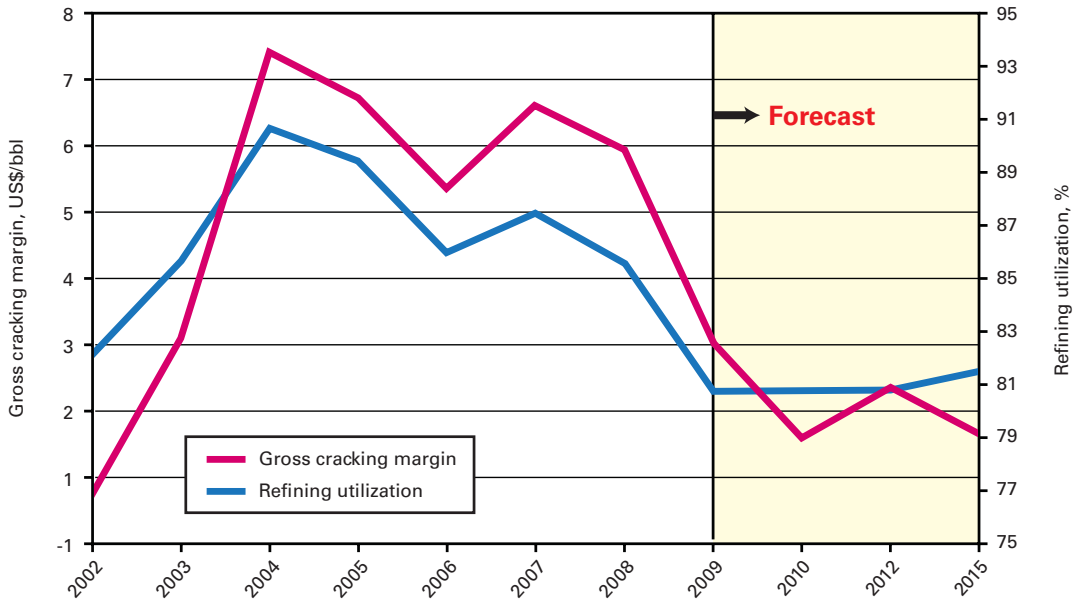
Fig. 2



*Singapore markets. Cracking yield based on resid cracking unit.

ASIA-PACIFIC REFINERY UTILIZATION, CRACK MARGINS

Fig. 3



133,000 b/d. The overriding reason for the reduction in crude runs is the rapid deterioration in oil demand since October 2008.

Sinopec has had to reduce its crude runs the most.

Not only does the company face incursions into its territory from local refineries and other state oil companies, but it also had built high inventories of both crudes and products as it faithfully followed government orders to import massive amounts of gasoline, diesel, jet fuel, and crude oil in the months leading up to the Beijing summer Olympics. As of December 2008, Sinopec had about 43 million bbl of product inventory and more than 80 million bbl of crude stock.

China National Petroleum Co./PetroChina have also had to cut crude runs for similar reasons. Because it is less downstream focused, however, the impact on the company is less pronounced.

When the fall 2008 Databooks were prepared, local refineries were being hit hard by low administered product prices and high crude cost that led to widely negative margins. Sinopec and CNPC/PetroChina continued to process crude at the request of the government, but many local refiners shut down.

The situation for private refiners has since improved, as international crude and fuel oil prices dropped. The increase in crude runs of the local refiners, however, is estimated to have been marginal. Those refiners continue to have difficulties accessing crude oil in a tightly restricted domestic market.

For 2010, we continue to see lower utilization for China but the magnitude of the cut is minor. As far as the running mode is concerned, diesel maximization as well as maximum production of petrochemical feedstock is targeted. Overall, the result is higher exports/lower imports.

India

In India, utilization will decline to the high 90% of nameplate capacity from more than 100%. We understand that Reliance's new Jamnagar refinery may run at less than 100% utilization for first-half 2009, in view of the regional and global economic downturn.

Furthermore, mechanical completion for Reliance's fluid catalytic cracking unit and coker will occur late in second-quarter 2009. Our estimates are that Reliance's utilization may be in the range of 75-80% for first-half 2009, slowly ramping up to 95-100% by 2010.

For existing and older refineries in India, utilization rates will vary between 85-90% in 2009 and 2010. For India as a whole, refinery utilization will decline to 97.0% in 2009 and 96.5% in 2010 from 109.1% in 2008.

Why will India's refinery utilization remain relatively high? In India, there is duty protection for the domestic refining sector owing to the positive differential between product and crude import duties (currently averaging 2.5%). The government-regulated domestic retail prices help ensure high utilization rates among public-sector oil marketing companies. Also, there are localized product deficits (especially for diesel) in India that allow such private-sector OMCs as Essar and Reliance to sell their products partially to public-sector OMCs at import-parity prices. Lastly, the high level of sophistication and complexity in Reliance and Essar refineries gives them a competitive edge in exports vs. Singapore and Europe refineries.

Notably, Reliance will have a distinct advantage over other refineries in the region in its ability to process extra heavy crude grades. Reliance's crude diet is to include extra heavy crudes such as Syrian, Mexican, Venezuelan, and heavy Middle Eastern grades (Soroush, Arab Heavy, etc.) with a general API gravity of 22-24°.

In comparison, the crude slate of Singapore and South Korean refiners is likely to be in the range of 32-34° API.

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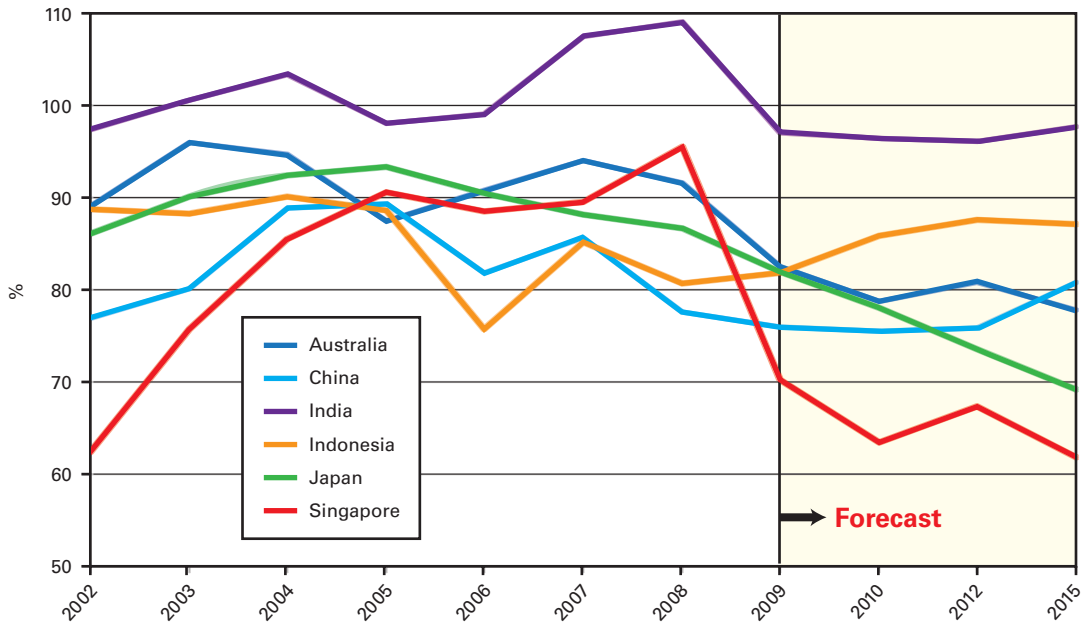
CALL FOR ABSTRACTS

REFINERY UTILIZATION IN SELECT COUNTRIES

Fig. 4



Reliance will have a $3-4/bbl advantage on crude costs over a generic Asian refinery running on typical Middle Eastern grades.

Reliance also has a 93% overall distillate yield vs. some 80-85% for other Asian refineries. In view of the projected light-heavy differentials, the company will have a $1/bbl advantage over a generic Asian refinery in terms of gross product worth. The high diesel yield of the RPL refinery will also be advantageous in view of strong diesel prices going forward.

Indonesia

Indonesia will remain as the largest importer of gasoline and diesel in the Asia-Pacific in 2009 and 2010. Pertamina's refineries cannot cope with the domestic demand for petroleum products.

Pertamina will try to maintain a high throughput for its refineries in 2009 and 2010 because this year Pertamina has been chosen again to be sole distributor and marketer of subsidized products in the country.

Japan

Among countries in the Asia-Pacific, Japan will be one of the worst hit by the global slowdown, as Japan's economic growth is led mainly by external demand. Contraction of demand for automobiles, electronics goods, and other machinery products in overseas markets are adversely affecting the manufacturing industry. Furthermore, because of structural demographic factors, demand for petroleum products in the domestic market is contracting drastically. Serious demand deterioration at home likely will force refiners to reassess how to deal with excess capacity.

Almost all refiners are trying to export products as a means to avoid closures. Total exports increased from 266,000 b/d in 2007 to some 375,000 b/d in 2008, of which diesel is estimated to account for 200,000 b/d.

Export growth will likely lose momentum in the coming years, however. Demand slowdown in Asia and a series of new and large export refineries in Asia and the Middle East entering the global market will intensify competition in the export market. In 2009, Japanese exports will likely fall to 280,000 b/d. Because export margins will remain weak, Japan's exports will likely decline for the medium term. Pressure will mount for additional closures.

Nippon Oil, the biggest Japanese refiner, plans to restructure its business and operation through a planned merger with Nippon Mining Holdings. By achieving extensive integration in oil refining and marketing, Nippon Oil and Nippon Mining hope to achieve savings of at least 60 billion yen ($662 million)/year. The merged entity plans to reduce refining capacity by 400,000 b/d, which is about 20% of current total refining capacity of 1,852,000 b/d. Closing of an additional 400,000 b/d is possible. Even assuming they will remove the suggested capacity, we believe there still remains excess capacity.

Japanese refiners are facing a surplus at a time of massive global refining surplus. The need to optimize production, logistics, and commercial competitiveness requires strategic and innovative decisions. Forming alliances and joint ventures will become more important for the industry in order to help ease the costly, as well as socially and culturally complex processes of closing regional refineries

Malaysia

Malaysian refineries in aggregate are likely to cut throughput by only 30,000 b/d to reduce naphtha and middle distillate production. Malaysia is a net exporter of naphtha and kerosine and jet fuel, but because Malaysia is heavily gasoline deficit, refineries only cut rates marginally to avoid sacrificing gasoline production.

Although Esso Port Dickson is a simple hydroskimming refinery, it will only

cut rates a little, given that it has a large reformer. Similarly, Shell Port Dickson is likely to cut rates marginally because it also has a reformer and a residue-cracking unit to meet gasoline deficits, although Shell is sensitive to refinery economics.

PSR-2 is highly complex and will not cut rates, although it is undergoing expansion to increase its crude distillation capacity by 30,000 b/d at the moment. PSR-2 has sizeable upgrading units that are underutilized due to its relatively small crude unit compared with the size of its upgrading units. In addition, PSR-2 is also able to keep its feedstock costs low by having Sudan's acidic Dar Blend as part of its crude diet.

Because PSR-1 has just had lubes installed, it is unlikely to cut rates much. The refinery also has a large reformer to meet gasoline deficits.

Petronas's Kerteh refinery will likely cut rates due to the petrochemicals downturn.

Philippines

Philippine refineries in 2008 were already running at a low 66% utilization, partly due to the cat cracker expansion in Petron. In 2009, refineries will increase their throughput to 72%, just enough to fill the upgrading units.

Petron Corp. is unlikely to cut too much because it just installed a new resid-cracking unit in 2008 and this year is installing an aromatic plant.

Singapore

With their cracking margins expected to fall sharply to a level last seen in 2001, export-oriented refineries in Singapore will have to cut crude runs sharply. They will likely only fill upgrading units.

Total crude runs in Singapore refineries will come down to around 910,000 b/d in 2009, from a high of 1.24 million b/d in 2008. Given a lower cracking margin and a negative hydroskimming margin, both ExxonMobil and Shell refineries will be forced to reduce utilization to around 50-60%. Their refineries have comparatively large crude distillation capacities compared with upgrading units.

Having a higher complexity, Singapore Refining Co. will have to cut but only to around 75-80% utilization.

Singapore's refineries will continue to rely on both the domestic market and neighboring countries in Southeast Asia that are net deficit of oil products, particularly Indonesia, Malaysia, and Vietnam.

South Korea

Because Korea is a large product exporter, the impact of the crisis will be sharply felt. South Korean refiners will have to reduce throughput by close to 200,000 b/d in 2009 compared with 2008, which means they will run at about 84%. Incheon and Hyundai face the greatest cuts due to relatively low complexity.

In accordance with its respective complexity, the response of each refinery in South Korea will vary. SK Incheon has simple hydroskimming and may temporarily shut down a crude unit of around 60,000 b/d. S-Oil, in contrast, is highly upgraded but exports a lot of oil products. Instead of shutting down one of its crude units, therefore, SK will likely reduce crude throughput. Hyundai is very sensitive to margins. Until the company completes its planned resid and atmospheric resid distillation units, Hyundai will lower its crude throughput also in 2009.

Because SK Ulsan completed a 60,000-b/d resid unit in mid 2008 and GS Caltex just completed a large hydrocracking unit and lubes, they may largely maintain output.

Taiwan

FGE's fall 2008 Databook projected Taiwan's crude runs to be 955,000 b/d for 2008 and 970,000 b/d for 2009. The latest assessment for 2008 put crude runs averaging only 900,000 b/d. For 2009, crude runs will come down further, to 890,000 b/d. Drastic reductions in domestic demand and worsening refining margins in Asia-Pacific are the main reasons for the cuts in refining throughput.

CPC should be able to maintain its overall refining utilization at slightly more than 70% because state-owned CPC Corp. holds about three quarters of the domestic market. CPC exports only around 15% and 25%, respectively, of its gasoline and diesel output.

For the privately owned Formosa Petrochemical Corp., on the other hand, the impact of the slowdown is more severe. Formosa exports around 50% of its gasoline output and 85% of its diesel output and will consequently be more affected by the weak transport fuel export market this year. Utilization at Formosa's 504,000-b/d refinery will remain at less than 70%.

Beyond 2009 will see a gradual recovery of the refining business in Taiwan in 2010. Net increase in crude runs, however, will be moderate through 2012. By 2015, if the new CPC refinery is operating, there will be a lift

INDIA PRODUCT BALANCE

Table 2

2009	Ouput	Imports	Exports	Demand
LPG[1]	330	64	—	395
Naphtha[1]	406	100	195	311
Gasoline[2]	514	—	248	266
Kero/jet	363	25	98	290
Diesel[2]	1,423	20	373	1,069
Fuel oil	299	18	81	236
Other	295	1	—	296
Total	3,629	229	995	2,863
Dubai Crude	—	—	—	220

[1]Nonrefinery LPG: 75 Naphtha: 37. [2]Ethanol: 34 Biodiesel: 32.

2010	Output	Imports	Exports	Demand
LPG[1]	351	62	—	412
Naphtha[1]	435	85	186	334
Gasoline[2]	601	9	332	278
Kero/jet	403	30	154	279
Diesel[2]	1,593	15	508	1,099
Fuel oil	327	10	108	229
Other	319	—	11	308
Total	4,029	211	1,300	2,940
Dubai crude	0	—	—	0

[1]Nonrefinery LPG: 80 Naphtha: 37. [2]Ethanol: 46 Biodiesel: 68.

in Taiwan's crude throughput. With a significantly lower demand, Taiwan is likely to remain a net product exporter throughout the forecast period by 2015.

Thailand

In 2009, Thailand's refining sector faces the challenge of operating in an environment of flat to declining demand for all products except for LPG. The initial response of the refining sector is to export production surpluses into the region, which already has a surplus in petroleum products. Thailand will need to keep utilization low at 81%.

The global economic downturn might force Integrated Refining and Petrochemical Co. to shelve or defer its crude unit's expansion. Having a less complex refinery that serves mainly downstream chemicals, the company may have to cut its crude runs by around 40,000 b/d.

In contrast, Thaioil is well upgraded and has a history of running at more than 100% of nameplate capacity. Thailoil may have to reduce its utilization slightly. Chevron's refinery has upgrading plans also but is sensitive to economics. We expect it to reduce crude throughput.

In early 2009, Bangchak completed its long-awaited hydrocracker that will shift it close to maximum capacity. PTT Aromatics and Refining Public Co. Ltd. will bring its condensate splitter and aromatics complex on line during the downturn.

Vietnam

Dung Quat started up in February 2009 (OGJ Online, Feb. 27, 2009). The refinery will start up at around 30%, reaching full capacity by yearend 2009. Vietnam has sharply reduced its products import program in anticipation of lower demand and refinery startup.

Vietnam is product deficit and its refinery has a massive residue cracker and reformer. The assumption we made was that Dung Quat will run at maximum in second-half 2009.

Product balances

Despite the reduction in utilization, Asian crude throughput in 2009 and 2010 will still be higher than seen in 2008 due to the increased refining capacity coming on stream in 2009. The major changes to refinery capacity are in China and India. Tables 1 and 2 show calculations on product balances for China and India.

Between 2008 and 2010, China will reduce its import requirements by around two-thirds due to increased refining capacity and lower demand growth. China is adding 776,000 b/d of crude capacity in 2009, while its demand will grow by only 182,000 b/d. Despite a reduction in refinery utilization, China will still have more product output in 2009 and 2010, compared with 2008.

China will be self-sufficient in

NELSON-FARRAR COST INDEXES

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

	1962	1980	2006	2007	2008	Feb. 2008	Jan. 2009	Feb. 2009
Pumps, compressors, etc.	222.5	777.3	1,758.2	1,844.4	1,949.8	1,910.8	2,010.9	2,010.9
Electrical machinery	189.5	394.7	520.2	517.3	515.6	513.2	517.3	516.4
Internal-comb. engines	183.4	512.6	959.7	974.6	990.9	986.5	1,018.7	1,019.3
Instruments	214.8	587.3	1,166.0	1,267.9	1,342.1	1,305.2	1,375.5	1,377.8
Heat exchangers	183.6	618.7	1,162.7	1,342.2	1,354.6	1,374.7	1,253.8	1,253.8
Misc. equip. average	198.8	578.1	1,113.3	1,189.3	1,230.6	1,218.1	1,235.2	1,235.6
Materials component	205.9	629.2	1,273.5	1,364.8	1,572.0	1,431.4	1,357.2	1,325.2
Labor component	258.8	951.9	2,497.8	2,601.4	2,704.3	2,663.0	2,785.5	2,785.5
Refinery (Inflation) Index	237.6	822.8	2,008.1	2,106.7	2,251.4	2,170.4	2,214.2	2,201.4

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

	1962	1980	2006	2007	2008	Feb. 2008	Jan. 2009	Feb. 2009
Fuel cost	100.9	810.5	1,569.0	1,530.7	1,951.3	1,819.2	1,156.2	988.0
Labor cost	93.9	200.5	204.2	215.8	237.9	214.7	265.6	259.1
Wages	123.9	439.9	1,015.4	1,042.8	1,092.2	997.8	1,175.3	1,141.2
Productivity	131.8	226.3	497.5	483.4	460.8	464.8	442.6	440.5
Invest., maint., etc.	121.7	324.8	743.7	777.4	830.8	800.9	811.0	806.4
Chemical costs	96.7	229.2	365.4	385.9	472.5	423.7	399.4	401.0
Operating indexes								
Refinery	103.7	312.7	579.0	596.5	674.1	635.8	597.8	578.2
*Process units**	103.6	457.5	870.7	872.6	1,045.1	981.4	768.2	705.7

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

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

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

diesel, which is the aim of government planners. Import requirements for fuel oil will also be reduced from around 390,000 b/d in 2008 down to 310,000 b/d in 2009.

Despite a reduction in utilization, India will also increase its product exports in 2009 and 2010. India is adding 674,000 b/d of refining capacity, while its demand will increase by only 66,000 b/d in 2009. Because import requirements from Northwest Europe and the US are falling, India will have to export more petroleum products to the Middle East, Africa, Southern Europe, as well as Asia.

Implications

On average, Asia-Pacific refinery utilization in 2009 and 2010 will fall to levels last seen in 2002. For those refineries that operate where domestic demand can absorb the refinery output, however, the downturn in utilization will be less dramatic (Fig. 4).

Despite the current credit crisis, the future is not all gloom and doom: Demand for oil products, especially in the developing countries in Asia-Pacific, will increase. The regional demand for oil products will catch up again with the growing refining capacity.

On positive impact of the crisis lies in the reality check it has brought to the exuberance that led to some refiners to expand capacity at breakneck speed. Witnessing the drop in refinery margins, national oil companies, and private and local refiners have begun to rethink their growth strategies.

Furthermore, those refiners that are still gung-ho to expand for political, strategic, or whatever reasons may face difficulties in getting the necessary financing from banks that are more conservative in their lending practices.

Due to delays in refinery buildup beyond 2010 and the expected recovery in oil demand, existing refineries should expect a mild recovery in refining margins after 2010. Unfortunately, this window of improved margins may close as Middle East expansions come on line middecade. ✦

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CORROSION CONTROL—1

Unmitigated MIC prompts integrity management changes

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Identifying unmitigated microbial-influenced corrosion (MIC) rather than mitigated or even unmitigated CO_2 corrosion as the highest risk to infield oil transport pipeline integrity has led to a change of emphasis in corrosion control, with the emphasis placed on water cut control at slow flow rates and optimization of the pigging program.

Microbial corrosion modeling can be used in addition to CO_2 corrosion modeling to show historical, present, and predicted future corrosion rates, leading to an increased level of confidence in future operations where pipelines damaged by MIC continue to be used.

This first of a two-part article concentrates on MIC modeling and subsequent intelligent in-line inspection of Forties pipelines. The concluding article (next week) will detail a leak that occurred despite these efforts and the response to it.

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

Background

Forties field began producing in 1975. Production from the field peaked in 1978 at 520,000 b/d. Acquired by Apache in 2003, the field still ranks in the top four North Sea fields in production and reserves even after having produced more than any other North Sea field: roughly 2.6 billion bbl to date. Apache raised production from 42,000 b/d to a peak of 81,000 b/d. In 2006, average daily production exceeded 58,000 b/d.[1]

Forties field consists of five platforms, Forties Alpha, Bravo, Charlie, Delta, and Echo (Fig. 1). Forties Charlie acts as the central hub for all Forties production as well as for several other UK sector North Sea fields, and ships Forties output with the 36-in. OD Forties Pipeline System (FPS) export line to Cruden Bay via the Unity platform.

Forties Alpha, Forties Charlie, and Forties Delta platforms have separation and processing facilities. Conversion of Forties Bravo platform from oil to direct export (transport of nonstabilized multiphase produced fluids) included

FORTIES FIELD PIPELINES

Table 1

Pipeline	Description	Service
PL 54	Forties Alpha to Forties Charlie, disused 20-in. OD oil rigid	n/a
PL 54A	Forties Alpha to Forties Charlie, 20-in. OD rigid	Crude oil
PL 55, now PL 2496	Forties Bravo to Forties Charlie 20-in. OD (now 14-in. OD) rigid	Multiphase oil-water fluids-gas
PL 56	Forties Delta to Forties Charlie, 20-in. OD rigid	Crude oil
PL 365	Forties Echo to Forties Alpha, 12-in. OD rigid	Multiphase oil-water fluids-gas
PL 380	Forties Echo to Forties Alpha, disused 6-in. OD rigid test	n/a
PL 2039	Forties Charlie to Forties Delta, 4.5-in. OD flexible	Fuel gas
PL 2040	Forties Alpha to Forties Delta, 4.5-in. OD flexible	Fuel gas
PL 2140	Forties Charlie to Forties Bravo, 8-in. OD flexible	Produced water

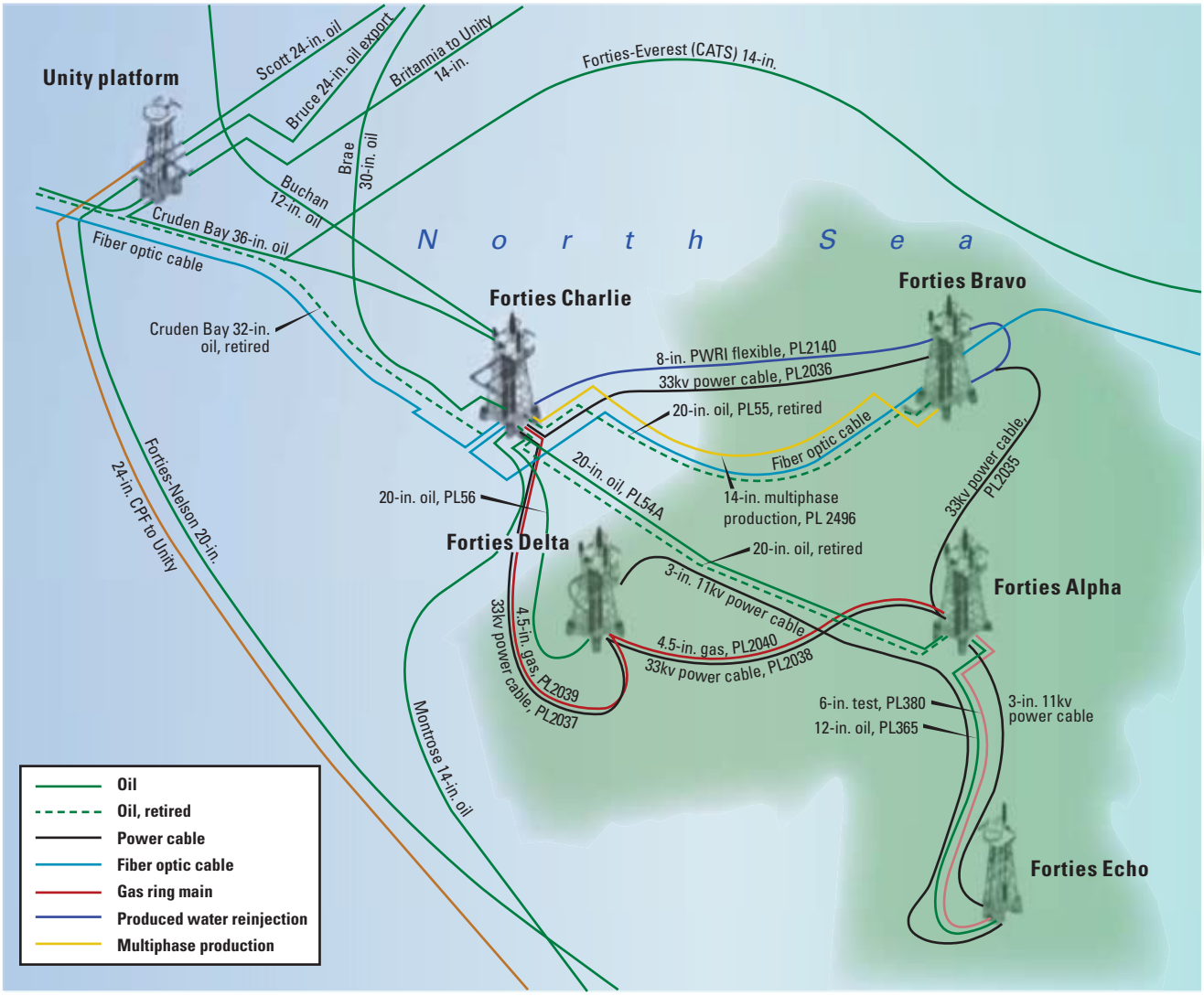
WATER CUT KEY PERFORMANCE INDICATOR, PROCESSED OIL TRANSPORT

Table 2

Pipeline type	Requirements
Water cuts, oil export lines (Forties Alpha to Forties Charlie, Forties Delta to Forties Charlie).	10% off for: Every 0.2% above 2% at an average flow rate >1 m/sec. Every 0.1% above 0.5% at an average flow rate 0.7 m/sec and <1 m/sec. Every 0.1% above 0.2% at an average flow rate < 0.7 m/sec. 90% achieved over year.

FORTIES FIELD PIPELINES

Fig. 1



removal of separation and processing facilities.

Forties Echo platform does not include separation facilities. Nonstabilized multiphase oil-gas-produced water flows onto Forties Alpha for separation train processing. Table 1 describes Forties field's in-field pipeline system.

Low oil prices in the 1990s led to cuts and cost savings throughout the UK North Sea. The corrosion consequences of many of the operational deficiencies of the 1990s have only recently become apparent. Higher oil prices and increased emphasis on maintenance of ageing pipelines have prompted operators' efforts to stabilize the current corrosion situation and, where required, take remedial action.

Apache found a number of pipeline corrosion issues requiring examination on taking ownership of Forties. This article examines integrity issues tied to the in-line inspection program, including:

- Microbial-influenced corrosion (MIC) modeling of Forties' in-field pipelines, operational pigging, and water cut control.
- An intelligent pig run that failed to identify a defect, leading to a subsequent leak.
- The importance of rapid response when pipeline integrity issues occur.

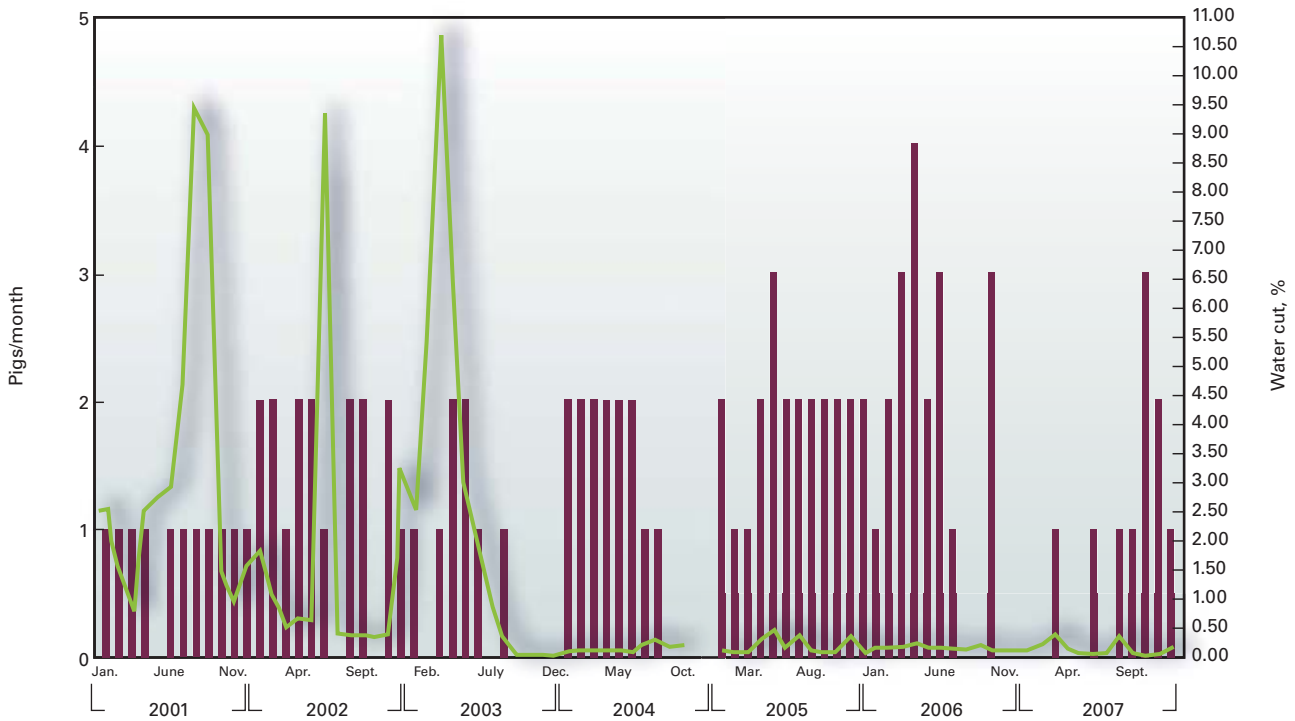
MIC, modeling

CO_2 corrosion modeling and risk assessment have established MIC as the highest risk corrosion mechanism for in-field oil transport pipelines.[2]

Low separator pressures and high levels of corrosion inhibition kept the probability of CO_2 corrosion in the oil transport lines low. The in-field oil transport lines act as feed source for inhibitor for the entire Forties pipeline system, requiring the high levels of corrosion inhibition. These lines, however,

WATER CUT, PIGGING HISTORY; DELTA-TO-CHARLIE

Fig. 2



now transport <15% of their design capacity and flow rates are <0.3 m/sec. Arrival temperatures at Forties' Charlie facilities measure 20-25° C., creating a high risk of unmitigated microbial corrosion.

An intelligent pigging program led to replacement of one infield pipeline (Forties Bravo to Forties Charlie). Work on a second pipeline (Forties Delta to Forties Charlie) began in May 2009. Damage has occurred predominantly as isolated pitting at the 6 o'clock position. In some cases, however, pits have merged together to produce longer axial-length defects.

Operational requirements demanded investigation of two issues:

- Usability of the existing Forties Delta to Forties Charlie pipeline until its scheduled replacement in early 2009, given identified corrosion rates and damage profile
- Predicted MIC rate for life prediction of the Forties Alpha to Forties Charlie pipeline.

Microbial corrosion modeling, developed by Pots,[3] sheds light on these issues. Parameters influencing MIC rates include temperature, flow rate, water cut, pigging frequency, and biocide treatment. Commercial Microbiology Ltd. deployed a modified variant of the Pots microbial corrosion model on Forties Alpha to Forties Charlie and Forties Delta to Forties Charlie oil transport pipelines.

FORTIES BRAVO TO FORTIES CHARLIE DESIGN INFORMATION

Table 3

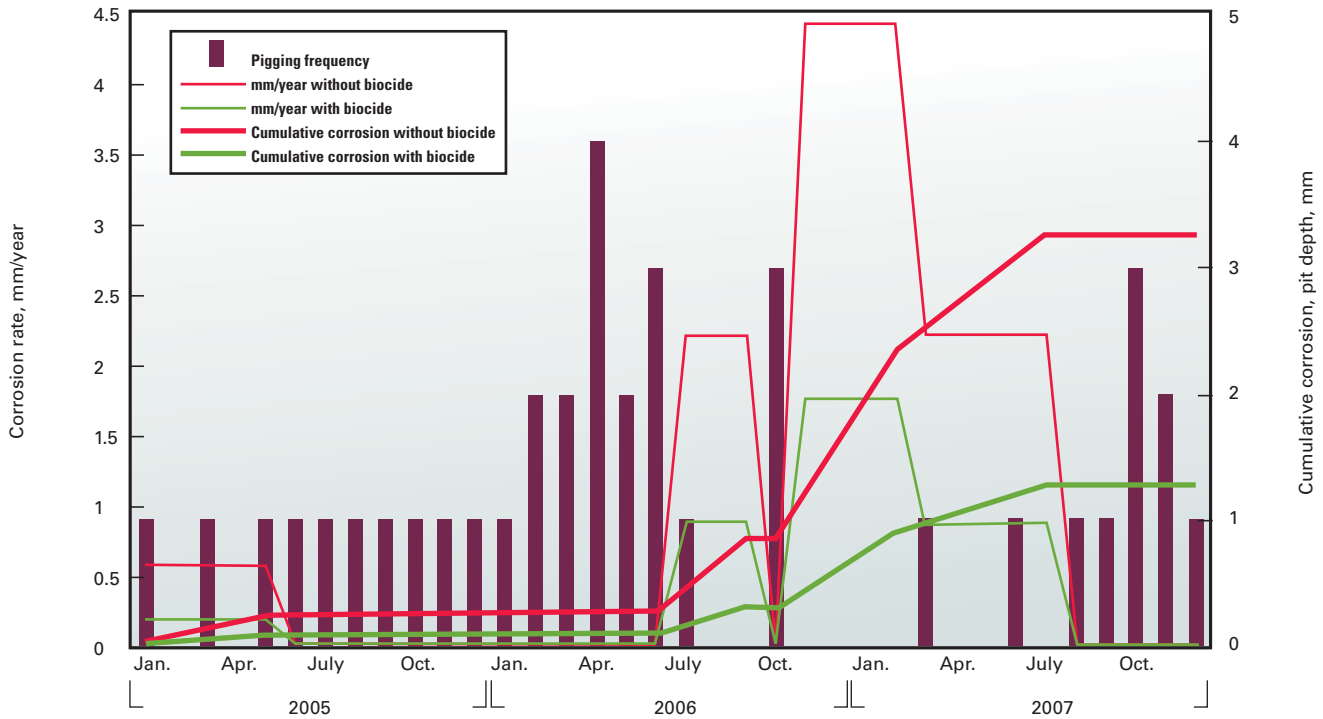
Parameter	Value
Design pressure	129 barg
MAOP	52 barg; reduced January 2007 following assessment
Typical operating pressure	16 barg, with spikes to 27 barg on start-up
OD	508 mm
Material	API 5L X65 spirally welded line pipe
Nominal WT	12.7 mm
API 5L WT tolerances	+19.5%/–8.0%
Burial status	Installed unburied on seabed
Operating temperature	Up to 82° C.

Delta-to-Charlie pipeline

Installed in 1975, the Delta-to-Charlie pipeline received its first intelligent pigging in 1998. Risers had remained in relatively good condition. Pitting and axial grooving damage, however, existed at the 6 o'clock position of the transport line. Pipeline wall penetration and defect growth rates required derating of the maximum allowable operating pressure (MAOP) to continue use. A 2001 reinspection found no meaning-

MIC MODELING, DELTA-TO-CHARLIE

Fig. 3



ful defect growth rate, allowing the line to continue functioning at its reduced MAOP.

A 2007 reexamination of worst-case defects found in 2001 observed no defect growth. But completely new defects appeared and growth of some of the smaller defects had accelerated. Corrosion rates measured >1 mm/year, faster than could be accounted for by CO_2 corrosion. Even assuming inhibitor efficiency of 0%, the worst case modeled CO_2 corrosion rate measured 0.5 mm/year. Evidence of sulfate-reducing bacteria (SRB) activity and H_2S formation in other pipelines in the field and topsides facilities, combined with risk assessment results, led this damage to be attributed to MIC.

Fig. 2 presents historical water cut and cleaning pig data for the Forties Delta to Forties Charlie pipeline. Water cut control was relatively poor before 2003. After 2003 water cut control improved. Cleaning pigs have since run on a regular basis. Between mid-2006 and mid-2007, however, damage to an isolation valve caused few pigs to run.

Fig. 3 presents results of MIC modeling for this pipeline from 2005 onwards, a period in which the water cut was low. Predicted microbial corrosion rates generally measured <0.1 mm/year, with the previously discussed exception from mid-2006 to mid-2007. While pigging frequency was reduced, predicted corrosion rates peaked at more than 4 mm/year in the absence of biocide, raising the possibility the damage noted between 2001 and 2007 occurred during this period.

But the pipeline used high levels of corrosion inhibition during this period. Even assuming corrosion inhibition is ineffective against MIC, the toxicity of the high dosage (well in excess of 100 ppm, based on total fluids) and its tendency to partition in the aqueous phase should have made it relatively biocidal.

Fig. 4 confirms the inhibitor's biocidal capability in the aqueous phase. The corrosion inhibitor at concentrations as low as 35 ppm is as biocidal as gluteraldehyde at 150 ppm. Fig. 3 shows the total predicted 2005-08 metal loss in the presence of a biocide as <1.5 mm. This level of biocide is inconsistent with the damage found by comparing intelligent pig runs from the period. High rates of MIC between 2001 and 2003 more likely caused the damage during the high water-cut periods.

Subsequent relatively low MIC rates brought about by an effective pigging program

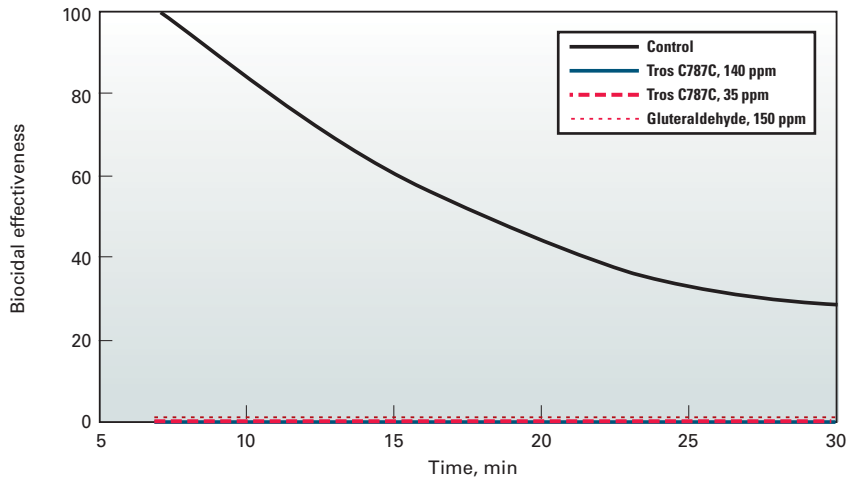
SIZING CAPABILITY COMPARISON

Table 4

	Standard magnetic flux leakage	MagneScan Triax MFL
Depth-sizing accuracy	±10%	±10%
Length-sizing accuracy	±0.787 in.	±0.394 in.
Width-sizing accuracy	±0.787 in.	±0.59 in.
Confidence	80%	90%

CORROSION INHIBITOR BIOCIDE ASSESSMENT, DELTA-TO-CHARLIE

Fig. 4



have allowed replacement of this pipeline to be scheduled to coincide with a planned 2009 shutdown of Forties Delta platform.

Processed-oil pipeline

Installation of this replacement for PL54 occurred in 1995. It was intelligently pigged in April 2009. Although the full results of that inspection are still being prepared, preliminary reporting shows the pipeline remains fit for service.

Fig. 5 shows water cut control was relatively poor before 2003. Control improved substantially after 2003. MIC modeling carried out by Commercial Microbiology Ltd. predicted corrosion rates as high as 2.2 mm/year, with rates reduced to <0.1 mm during periods of low water cut and effective pigging. These rates, combined with the fact the original line required replacement after only 20 years of service, lead to the 2008 intelligent pig survey.

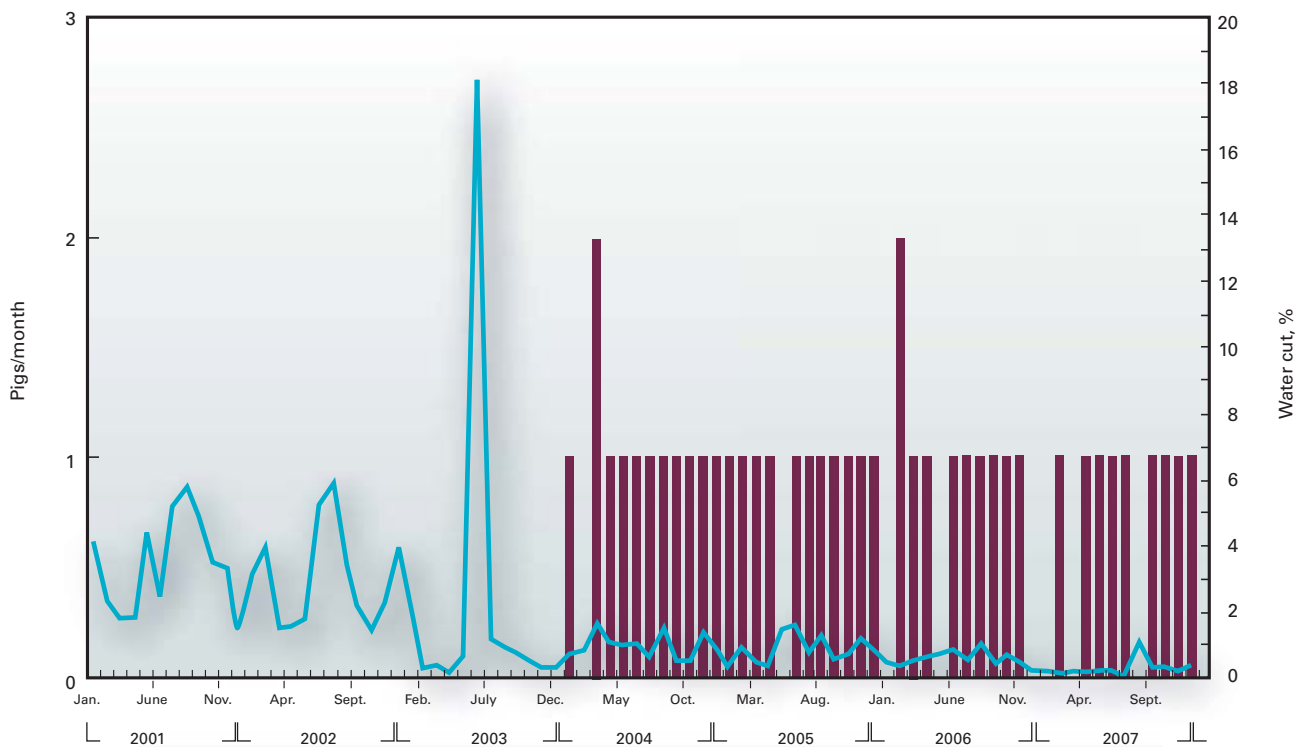
Water-cut control

Intelligent pig results, combined with risk assessment and microbial corrosion modeling, prompted changes in water cut control and pigging operations.

Previous water cut limits stood at 2%. Industry participants generally believe holding water cut <1-2% allows mitigation of water drop and associated microbial and corrosion issues, an erroneous belief to some extent. A 1-2% water cut can be successfully entrained, even in light crudes.[4] Entrainment, however, requires maintaining a crude flow rate of >1 m/sec. As flow rate drops below 1 m/sec, a rapid drop in water entrainment capability occurs, and light crudes flowing at low veloci-

WATER CUT, PIGGING HISTORY; ALPHA-TO-CHARLIE

Fig. 5



ties (<0.2 m/sec) might have difficulty maintaining even 0.2% water entrainment.

Design of many North Sea facilities' pipelines envisioned peak oil flows well more than current rates of ≤1 m/sec. A 1-2% water cut assumption under these circumstances is not an acceptable integrity criterion.

Processed oil water cuts in Forties field under Apache have typically measured <0.5%. Flow rates in the infield oil transport lines, however, are <1 m/sec and the water entrainment capability of the relatively light Forties field crude will be lower than this value. The key performance indicator (KPI) for water cut now reflects this situation and provides a stepped water content target based on pipeline flow velocity. Table 2 shows the modified KPI.

Intelligent pigging

On Apr. 4, 2008, the Forties Bravo to Forties Charlie pipeline, converted to multiphase flow in late 2006 after 31 years as a processed oil transport line, suffered a minor leak. The pipeline had a design pressure of 129 barg. In January 2007, an MAOP reduction to 52 barg followed an assessment based on corrosion modeling and comparison with internal corrosion seen in other pipelines with similar operating conditions. Table 3 shows summary design information for the pipeline.

An in-line inspection shortly before the leak occurred confirmed widespread internal corrosion but no more than incidental metal loss at the leak. The leak occurred at the intersection of a line pipe spiral weld and the butt weld between two pipe lengths, near the bottom of the pipeline.

An in-line inspection in 1990 by H. Rosen Engineering GMBH of the Forties Bravo to Forties Charlie pipeline using a corrosion-detection pig reported limited internal corrosion. Apache selected GE Energy's Pipeline Integrity International division for its initial in-line inspection program, using its MagneScan TRIAX in-line inspection technology.

This technology can read magnetic flux leakage (MFL) signals on three separate axes (vs. the one or two used by traditional MFL tools) enabling detection of general and axial defects from the same inspection data and offering improved sizing capability compared with traditional MFL tools. Table 4 offers a comparison of sizing capabilities.

Anticipated flow velocities in the pipelines of less than the minimum 1 m/sec for standard MFL required use of the GE system with its minimum velocity of 0.3 m/sec. Delays in performing the surveys, however, pushed inspection of the Forties Bravo to Charlie pipeline to after the change from transmission of processed crude oil to the direct export of multiphase water-crude oil-gas, resulting in increased flow velocity.

The in-line survey of the Forties Bravo to Charlie pipeline in June 2007 identified widespread internal corrosion, particularly at the 6 o'clock position at the bottom of the pipeline. The corrosion damage consisted of numerous individual features, the vast majority of which measured <30% WT and lay within the first 3 km from Forties Bravo. The deepest features had a relatively short axial length. The inspection also identified evidence of preferential weld corrosion, although none of these instances was identified as serious.

Inspection reported two internal metal loss features with depths >80% WT; 83% × 88 mm and 85% × 33 mm (peak depth as percentage of nominal WT × axial length). Assessment of the corrosion features, however, did not deem any to be unsafe at the pipeline's current 52 barg MAOP (reduced from its original 129 barg), the highest calculated estimated repair factor (ERF) measuring 0.720. ERF is the ratio of MAOP to the calculated safe operating pressure for the identified metal loss features. An ERF value >1 indicates an unsafe condition if the pipeline is operated at or above the MAOP. DNV RP F101, October 2004, guided determination of the safe operating pressure.[5]

The typical pipeline operating pressure of 16 barg, with pressure spikes up to 27 barg, prompted the operator to consider failure by leak more likely than failure by rupture.[6] Continuing internal corrosion at the deepest metal loss features such as the two features with peak depths >80% would most likely cause these leaks, despite continuing efforts at corrosion mitigation through inhibition and routine pigging.

A repair program proposed for the pipeline was to address the highest metal-loss features, with additional repairs occurring during the pipeline's remaining life (to 2020).

The combination of predicted lifetime repair costs and future risk of leakage prompted a decision to replace the pipeline. Agreements for supply of line pipe and installation of the replacement pipeline occurred within days. Installation of replacement line took place during September 2007, with tie-in of the existing 20-in. OD risers at Forties Bravo and Charlie scheduled for the next platform maintenance program in April 2008. ✦

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Equipment/Software/Literature

New BOP has 20,000 psi working pressure

The new EVO 18¾ in., 20,000 psi working pressure blowout preventer is designed to meet the challenges of higher pressures and higher temperatures.

The EVO BOP is compact yet powerful, with a smaller footprint for less impact on the drilling rig. The firm says the unit offers superior reliability because of its design and step-changing lock.

Source: **Cameron,** 4646 W. Sam Houston Parkway N., Houston, TX 77041.

Software combines GIS, SCADA information

CygNet 7.2 is an upgrade of this firm's enterprise operations platform used in exploration, production, and gas transportation operations.

This version combines geographic information system and asset management information with its operational supervisory control and data acquisition module. This integration has been developed to help ensure both systems maintain their individual system of record status. Release 7.2 also is designed to help improve the methods of and performance for accessing and storing massive amounts of data.

CygNet 7.2 collects, manages, and distributes data. It is designed to enable organizations to increase operational efficiency and improve business decisions by turning raw data collected from diverse systems and devices into actionable information.

The company says this platform ensures reliability across a geographically diverse organization by leveraging the same network-centric architecture found in today's high-bandwidth video and imaging applications, known for consistently delivering massive amounts of data to various systems and end-user clients.

Source: **CygNet Software,** 994 Mill St., Suite 201, San Luis Obispo, CA 93401.

New LCD monitor water resistant, sunlight readable

The new Model TT-840 environmentally sealed LCD monitor promises to survive the demanding effects of harsh environments.

It is an 8.4 in. sunlight readable unit encapsulated in an aluminum enclosure that has been sealed to IP68/NEMA 6P specifications. It is watertight, surviving liquid, dust, and dirt intrusion. The LCD will operate in temperatures of –20° to +60° C.

The unit features a vivid sunlight readable display with up to 1,000 nits of brightness and a 600:1 contrast ratio suiting it for outdoor or high ambient light conditions. Backlights offer low power consumption, long-life, and increased vibration and shock protection, the firm notes.

The TT-840 monitor operates with a 12-36 v DC power input, which suits it for DC powered applications typically found in mobile applications. Power, video, and USB connections are provided through IP68 waterproof connectors directly on the unit.

Source: **Stealth.com Inc.,** 530 Rowntree Dairy Rd., Bldg. Four, Woodbridge, Ont. L4L 8H2.

Services/Suppliers

Wild Well Control Inc.,

Houston, has named Freddy Gebhardt president. Since 2005, he has served as executive vice-president and general manager of WWC. Gebhardt's career in the energy industry spans more than 30 years, with a focus on well control and blowout response and prevention, well capping, snubbing, and coiled tubing operations. He first joined WWC in 1983 as a senior well control specialist.

Gebhardt

WWC provides worldwide services to the energy industry, including firefighting, well control, and related engineering services, marine engineering, and well control training.

Global Oilfield Services,

Houston, has signed a definitive agreement to acquire the Green Country Submersible Pumps business of Green Country Supply Inc., a subsidiary of Chaparral Energy Inc. Closing is expected by the end of the second quarter. As part of funding for the acquisition, Global has reached agreement for a line of equity from Pine Brook Road Partners LLC. Pine Brook will provide up to $100 million of funding over time. In a related move, Global has added Pine Brook managing directors Arnold Chavkin, Michael McMahon, and investment professional Alex Bell to its board of directors. Former Global directors Peter Goode and Victor Grijalva will continue to serve on the board.

Pine Brook is a New York-based private equity firm established in 2006 by a team of private equity professionals to make business-building and other equity investments, primarily in the energy and financial services sectors.

Green Country manufactures, repairs, and distributes electrical submersible pumping equipment.

Global manufactures, installs, and services artificial lift equipment for the global onshore production market.

Victaulic Co.,

Easton, Pa., has promoted Grady Wilkerson to vice-president, sales. Previously, he was US divisional manager for Victaulic since 2003. Wilkerson will help develop and increase Victaulic's presence in the global oil, gas, and chemical markets. He joined Victaulic in 1980 in sales as part of the West Texas Oil Metro Group in Odessa, Tex. Wilkerson progressed up the ranks as territory manager in San Antonio, regional manager in Kansas City and later Houston, assistant US divisional manager, and national business development manager.

Wilkerson

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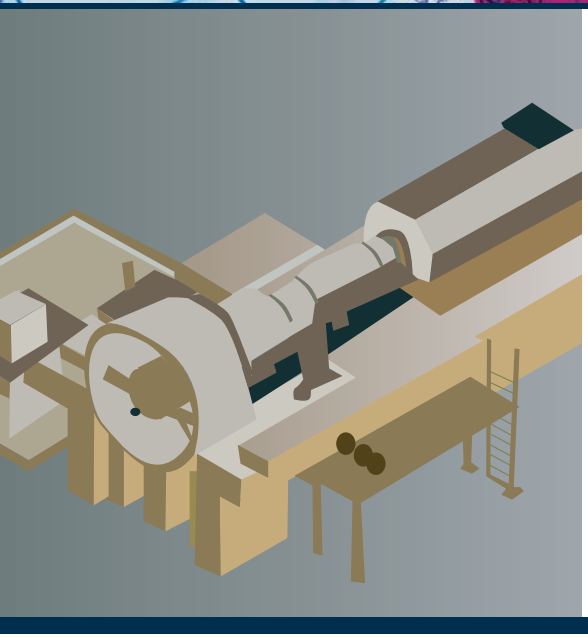


Two New Alstom 50-Hz Combined Cycle 140-MW Steam Turbine Generators Available for Immediate Shipment.

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.

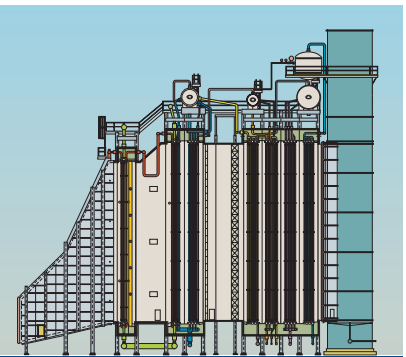
- Units come complete with all normally supplied auxiliaries and include factory warranties covering manufacturing defects and performance guarantees.
- Configured as a two-cylinder machine with an HP turbine and a combined IP/LP turbine with an axial exhaust.
- Steam inlet conditions are 1900 psia (nominal)/1050°F/1050°F.
- 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 INC. exclusively through PennEnergy

For Info or Pricing Contact

Randy Hall rhall@pennenergy.com P: 713-499-6330 | Bart Zaino bzaino@thomassenamcot.com P: 817-263-3273

Statistics

Imports of crude and products

	Districts 1–4		District 5		Total US		
	5-15 2009	5-8 2009	5-15 2009	5-8 2009	5-15 2009	5-8 2009	*5-16 2008
	1,000 b/d						
Total motor gasoline	880	641	58	106	938	747	1,143
Mo. gas. blending comp.	573	403	55	40	628	443	646
Distillate	173	167	0	39	173	206	198
Residual	252	237	59	48	311	285	482
Jet fuel-kerosine	128	45	42	13	170	58	161
Propane-propylene	94	90	5	2	99	92	164
Other	498	637	(58)	(12)	440	625	713
Total products	**2,598**	**2,220**	**161**	**236**	**2,759**	**2,456**	**3,507**
Total crude	**7,782**	**7,789**	**1,009**	**919**	**8,791**	**8,708**	**9,237**
Total imports	**10,380**	**10,009**	**1,170**	**1,155**	**11,550**	**11,164**	**12,744**

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

Purvin & Gertz LNG netbacks—May 22, 2009

Receiving terminal	Liquefaction plant					
	Algeria	Malaysia	Nigeria	Austr. NW Shelf	Qatar	Trinidad
	$/MMbtu					
Barcelona	7.32	5.37	6.56	5.27	5.90	6.49
Everett	3.57	1.36	3.25	1.47	2.01	3.82
Isle of Grain	3.02	1.26	2.51	1.17	1.70	2.53
Lake Charles	1.97	-0.19	1.66	-0.05	0.11	2.55
Sodegaura	3.56	5.53	3.81	5.26	4.64	3.02
Zeebrugge	4.43	2.75	3.94	2.67	3.19	3.98

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	14,667	53,702	35,573	11,000	57,545	15,405	3,643
PADD 2	84,949	47,587	20,651	7,323	32,976	1,321	17,605
PADD 3	190,340	70,061	40,243	12,660	42,573	15,583	25,768
PADD 4	16,817	5,375	1,981	506	3,208	252	[1]928
PADD 5	61,751	27,229	21,913	8,176	11,825	4,400	—
May 15, 2009	**368,524**	**203,954**	**120,361**	**39,665**	**148,127**	**36,961**	**47,944**
May 8, 2009	**370,629**	**208,291**	**122,355**	**40,126**	**147,455**	**36,680**	**46,193**
May 16, 2008[2]	**320,442**	**209,413**	**105,635**	**40,122**	**107,790**	**40,930**	**34,028**

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

Refinery report—May 15, 2009

District	REFINERY OPERATIONS		REFINERY OUTPUT				
	Gross inputs	Crude oil inputs	Total motor gasoline	Jet fuel, kerosine	Fuel oils: Distillate	Fuel oils: Residual	Propane–propylene
	1,000 b/d						
PADD 1	1,267	1,264	2,427	80	391	102	55
PADD 2	3,203	3,183	1,969	215	874	57	245
PADD 3	6,935	6,782	2,651	621	2,205	275	656
PADD 4	579	548	293	28	166	12	[1]66
PADD 5	2,473	2,332	1,395	366	496	121	—
May 15, 2009	**14,457**	**14,109**	**8,735**	**1,310**	**4,132**	**567**	**1,022**
May 8, 2009	**14,792**	**14,424**	**8,710**	**1,357**	**4,130**	**563**	**1,014**
May 16, 2008[2]	**15,464**	**15,083**	**9,028**	**1,560**	**4,344**	**648**	**1,117**
	17,672 Operable capacity		**81.8% 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

	*5-22-09	*5-23-08	Change	Change, %
	$/bbl			
SPOT PRICES				
Product value	70.01	144.84	–74.83	–51.7
Brent crude	58.14	127.93	–69.79	–54.6
Crack spread	11.87	16.91	–5.04	–29.8
FUTURES MARKET PRICES				
One month				
Product value	70.90	148.42	–77.52	–52.2
Light sweet crude	60.69	130.46	–69.77	–53.5
Crack spread	10.21	17.96	–7.75	–43.1
Six month				
Product value	68.58	144.99	–76.41	–52.7
Light sweet crude	63.88	130.49	–66.61	–51.0
Crack spread	4.70	14.50	–9.80	–67.6

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

OGJ GASOLINE PRICES

	Price ex tax 5-20-09	Pump price* 5-20-09	Pump price 5-21-08
		¢/gal	
(Approx. prices for self-service unleaded gasoline)			
Atlanta	183.4	229.9	389.1
Baltimore	184.0	225.9	376.1
Boston	182.0	223.9	370.4
Buffalo	170.0	230.9	394.0
Miami	175.9	227.5	399.7
Newark	191.9	224.5	368.4
New York	155.0	215.9	378.3
Norfolk	180.2	218.6	363.9
Philadelphia	180.9	231.6	381.7
Pittsburgh	184.2	234.9	380.4
Wash., DC	202.5	240.9	388.9
PAD I avg	180.9	227.7	381.0
Chicago	181.1	245.5	412.3
Cleveland	183.4	229.8	368.3
Des Moines	185.4	225.8	364.3
Detroit	172.4	231.8	378.3
Indianapolis	165.4	224.8	374.3
Kansas City	183.8	219.8	356.3
Louisville	184.9	225.8	386.0
Memphis	185.0	224.8	361.0
Milwaukee	178.5	229.8	391.2
Minn.-St. Paul	184.8	228.8	370.2
Oklahoma City	178.5	213.9	361.3
Omaha	172.5	217.8	367.3
St. Louis	179.8	215.8	374.2
Tulsa	179.4	214.8	354.3
Wichita	177.4	220.8	360.0
PAD II avg	179.5	224.7	372.0
Albuquerque	182.6	219.0	363.3
Birmingham	177.7	217.0	368.3
Dallas-Fort Worth	175.6	214.0	370.3
Houston	175.9	214.3	365.3
Little Rock	176.8	217.0	367.3
New Orleans	183.5	221.9	364.3
San Antonio	178.6	217.0	361.3
PAD III avg	178.7	217.2	365.7
Cheyenne	191.5	223.9	349.4
Denver	186.5	226.9	380.1
Salt Lake City	179.0	221.9	363.2
PAD IV avg	185.7	224.2	364.2
Los Angeles	165.3	232.4	406.7
Phoenix	184.0	221.4	359.9
Portland	199.0	242.4	383.6
San Diego	184.3	251.4	416.9
San Francisco	189.6	256.7	422.5
Seattle	186.5	242.4	392.6
PAD V avg	184.8	241.1	397.0
Week's avg.	**180.9**	**226.5**	**376.3**
Apr. avg.	**156.7**	**202.3**	**339.3**
Mar. avg.	**147.6**	**193.2**	**319.7**
2009 to date	**149.5**	**195.1**	—
2008 to date	**281.1**	**324.7**	—

*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

	5-15-09 ¢/gal		5-15-09 ¢/gal
Spot market product prices			
Motor gasoline (Conventional-regular)		Heating oil No. 2	
New York Harbor	163.75	New York Harbor	138.95
Gulf Coast	161.50	Gulf Coast	136.95
Los Angeles	170.25	Gas oil	
Amsterdam-Rotterdam-Antwerp (ARA)	166.43	ARA	142.25
Singapore	166.52	Singapore	152.02
Motor gasoline (Reformulated-regular)		Residual fuel oil	
New York Harbor	169.50	New York Harbor	119.36
Gulf Coast	166.50	Gulf Coast	129.10
Los Angeles	180.25	Los Angeles	150.76
		ARA	118.11
		Singapore	127.09

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

BAKER HUGHES RIG COUNT

	5-22-09	5-23-08
Alabama	4	5
Alaska	5	7
Arkansas	44	45
California	21	44
Land	20	42
Offshore	1	2
Colorado	45	119
Florida	1	0
Illinois	1	1
Indiana	2	2
Kansas	17	9
Kentucky	10	10
Louisiana	141	149
N. Land	75	53
S. Inland waters	6	21
S. Land	12	21
Offshore	48	54
Maryland	0	1
Michigan	0	1
Mississippi	9	12
Montana	0	10
Nebraska	1	0
New Mexico	35	76
New York	1	6
North Dakota	34	66
Ohio	8	11
Oklahoma	76	207
Pennsylvania	30	19
South Dakota	0	2
Texas	331	935
Offshore	2	10
Inland waters	0	2
Dist. 1	9	30
Dist. 2	13	35
Dist. 3	25	70
Dist. 4	38	95
Dist. 5	82	182
Dist. 6	54	122
Dist. 7B	9	32
Dist. 7C	8	69
Dist. 8	34	139
Dist. 8A	13	28
Dist. 9	21	39
Dist. 10	23	82
Utah	15	41
West Virginia	23	26
Wyoming	35	70
Others—NV-5; VA-5; WA-1	11	15
Total US	**900**	**1,889**
Total Canada	**74**	**152**
Grand total	**974**	**2,041**
US Oil rigs	180	386
US Gas rigs	711	1,493
Total US offshore	54	67
Total US cum. avg. YTD	**1,197**	**1,798**

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	5-22-09 Percent footage*	Rig count	5-23-08 Percent footage*
0-2,500	45	8.8	74	5.4
2,501-5,000	63	65.0	115	57.3
5,001-7,500	99	15.1	231	16.0
7,501-10,000	192	3.1	427	3.2
10,001-12,500	173	6.9	469	2.7
12,501-15,000	145	0.6	299	0.3
15,001-17,500	120	—	114	—
17,501-20,000	46	—	74	—
20,001-over	37	—	34	—
Total	**920**	**8.5**	**1,837**	**7.3**
INLAND	12		25	
LAND	862		1,755	
OFFSHORE	46		57	

*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]5-22-09	[2]5-23-08
	1,000 b/d	
(Crude oil and lease condensate)		
Alabama	21	21
Alaska	704	688
California	652	652
Colorado	63	65
Florida	6	4
Illinois	27	25
Kansas	101	104
Louisiana	1,439	1,305
Michigan	15	17
Mississippi	61	59
Montana	93	86
New Mexico	164	161
North Dakota	195	155
Oklahoma	176	170
Texas	1,349	1,339
Utah	58	56
Wyoming	149	145
All others	66	80
Total	**5,339**	**5,132**

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

US CRUDE PRICES

	5-22-09 $/bbl*
Alaska-North Slope 27°	42.37
South Louisiana Sweet	61.25
California-Kern River 13°	54.40
Lost Hills 30°	63.15
Wyoming Sweet	51.17
East Texas Sweet	57.75
West Texas Sour 34°	52.25
West Texas Intermediate	58.25
Oklahoma Sweet	58.25
Texas Upper Gulf Coast	51.25
Michigan Sour	50.25
Kansas Common	57.00
North Dakota Sweet	48.75

*Current major refiner's posted prices except North Slope lags 2 months. 40° gravity crude unless differing gravity is shown.
Source: Oil & Gas Journal.
Data available in OGJ Online Research Center.

WORLD CRUDE PRICES

$/bbl[1]	5-15-09
United Kingdom-Brent 38°	56.50
Russia-Urals 32°	55.45
Saudi Light 34°	53.40
Dubai Fateh 32°	57.17
Algeria Saharan 44°	57.36
Nigeria-Bonny Light 37°	58.34
Indonesia-Minas 34°	61.35
Venezuela-Tia Juana Light 31°	57.89
Mexico-Isthmus 33°	57.78
OPEC basket	56.83
Total OPEC[2]	55.71
Total non-OPEC[2]	56.06
Total world[2]	55.87
US imports[3]	55.21

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

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

US NATURAL GAS STORAGE[1]

	5-15-09	5-8-09	5-15-08	Change, %
		bcf		
Producing region	879	854	592	**48.5**
Consuming region east	892	827	789	**13.1**
Consuming region west	345	332	220	**56.8**
Total US	**2,116**	**2,013**	**1,601**	**32.2**
	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.

PACE REFINING MARGINS

	Mar. 2008	Apr. 2009	May. 2009	May. 2008	– 2009 vs. 2008 – Change	Change, %
			$/bbl			
US Gulf Coast						
West Texas Sour	3.80	5.94	5.51	17.01	–11.50	–67.6
Composite US Gulf Refinery	2.43	3.92	5.01	16.83	–11.82	–70.2
Arabian Light	0.19	1.43	4.26	13.43	–9.17	–68.3
Bonny Light	0.26	3.04	3.51	7.75	–4.24	–54.7
US PADD II						
Chicago (WTI)	2.47	5.56	7.78	24.65	–16.86	–68.4
US East Coast						
NY Harbor (Arab Med)	2.50	3.70	8.23	10.18	–1.95	–19.2
East Coast Comp-RFG	4.78	6.23	11.10	11.34	–0.24	–2.1
US West Coast						
Los Angeles (ANS)	3.73	9.42	5.02	14.14	–9.12	–64.5
NW Europe						
Rotterdam (Brent)	1.79	2.45	2.48	3.27	–0.78	–23.9
Mediterranean						
Italy (Urals)	1.73	3.39	2.59	9.38	–6.79	–72.4
Far East						
Singapore (Dubai)	2.07	3.53	2.42	6.85	–4.43	–64.7

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

US NATURAL GAS BALANCE DEMAND/SUPPLY SCOREBOARD

	Feb. 2009	Jan. 2009	Feb. 2008	Feb. 2009-2008 change	Total YTD 2009	Total YTD 2008	YTD 2009-2008 change
				bcf			
DEMAND							
Consumption	2,258	2,700	2,485	–227	4,958	5,203	–245
Addition to storage	100	79	56	44	179	124	55
Exports	89	117	103	–14	204	216	–12
Canada	58	86	63	–5	143	133	10
Mexico	28	28	37	–9	55	77	–22
LNG	3	3	3	0	6	6	0
Total demand	**2,447**	**2,896**	**2,644**	**–197**	**5,341**	**5,543**	**–202**
SUPPLY							
Production (dry gas)	1,629	1,782	1,624	5	3,411	3,335	76
Supplemental gas	5	6	4	1	12	6	6
Storage withdrawal	472	778	649	–177	1,250	1,541	–291
Imports	323	358	349	–26	681	737	–56
Canada	295	325	325	–30	620	684	–64
Mexico	0	6	0	0	6	1	5
LNG	28	27	24	4	55	52	3
Total supply	**2,429**	**2,924**	**2,626**	**–197**	**5,354**	**5,619**	**–265**

NATURAL GAS IN UNDERGROUND STORAGE

	Feb. 2009	Jan. 2009	Dec. 2008	Feb. 2008	Change
			bcf		
Base gas	4,242	4,236	4,229	4,222	20
Working gas	1,761	2,141	2,840	1,465	296
Total gas	**6,033**	**6,377**	**7,069**	**5,687**	**316**

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

WORLDWIDE NGL PRODUCTION

	Feb. 2009	Jan. 2009	2 month average production 2009	2 month average production 2008	Change vs. previous year Volume	Change vs. previous year %
			1,000 b/d			
Brazil	83	84	83	88	–4	–5.0
Canada	685	646	666	694	–28	–4.1
Mexico	364	366	365	367	–2	–0.5
United States	1,792	1,721	1,757	1,807	–50	–2.8
Venezuela	200	200	200	200	—	—
Other Western Hemisphere	203	202	202	201	2	0.8
Western Hemisphere	**3,328**	**3,218**	**3,273**	**3,356**	**–83**	**–2.5**
Norway	306	266	286	298	–12	–4.0
United Kingdom	169	156	162	181	–19	–10.6
Other Western Europe	10	10	10	10	—	–3.4
Western Europe	**447**	**457**	**448**	**441**	**7**	**1.7**
Russia	402	405	404	421	–18	–4.2
Other FSU	150	150	150	150	—	—
Other Eastern Europe	15	15	15	16	–1	–3.4
Eastern Europe	**567**	**570**	**569**	**587**	**–18**	**–3.1**
Algeria	341	350	346	351	–6	–1.6
Egypt	70	70	70	70	—	—
Libya	80	80	80	80	—	—
Other Africa	131	131	131	132	–1	–0.7
Africa	**622**	**631**	**627**	**633**	**-6**	**-1.0**
Saudi Arabia	1,311	1,305	1,308	1,440	–132	–9.2
United Arab Emirates	250	250	250	250	—	—
Other Middle East	835	835	835	870	–35	–4.0
Middle East	**2,396**	**2,390**	**2,393**	**2,560**	**–167**	**–6.5**
Australia	60	61	61	58	2	3.6
China	650	650	650	620	30	4.8
India	—	—	—	—	—	—
Other Asia-Pacific	169	169	169	181	–12	–6.5
Asia-Pacific	**879**	**880**	**880**	**859**	**20**	**2.4**
TOTAL WORLD	**8,277**	**8,121**	**8,199**	**8,485**	**–286**	**–3.4**

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

OXYGENATES

	Feb. 2009	Jan. 2009	Change	YTD 2009	YTD 2008	Change
			1,000 bbl			
Fuel ethanol						
Production	18,120	19,545	–1,425	37,665	30,843	6,822
Stocks	15,688	14,186	1,502	15,688	10,465	5,223
MTBE						
Production	1,353	1,394	–41	2,747	3,150	–403
Stocks	1,175	1,496	–321	1,175	1,642	–467

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

US HEATING DEGREE-DAYS

	Apr. 2009	Apr. 2008	Normal	2009 % change from normal	Total degree-days July 1 through Apr. 30 2009	Total degree-days July 1 through Apr. 30 2008	Total degree-days July 1 through Apr. 30 Normal	% change from normal
New England	514	516	583	–11.8	6,380	5,983	6,264	1.9
Middle Atlantic	450	392	496	–9.3	5,651	5,118	5,655	–0.1
East North Central	501	472	510	–1.8	6,361	6,076	6,209	2.4
West North Central	522	572	472	10.6	6,624	6,647	6,493	2.0
South Atlantic	182	172	179	1.7	2,840	2,460	2,785	2.0
East South Central	230	260	216	6.5	3,485	3,321	3,521	–1.0
West South Central	121	137	94	28.7	2,078	2,138	2,269	–8.4
Mountain	437	433	426	2.6	4,515	4,773	4,894	–7.7
Pacific	326	321	298	9.4	2,830	3,050	2,970	–4.7
US average*	**346**	**337**	**345**	**0.3**	**4,305**	**4,142**	**4,326**	**–0.5**

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

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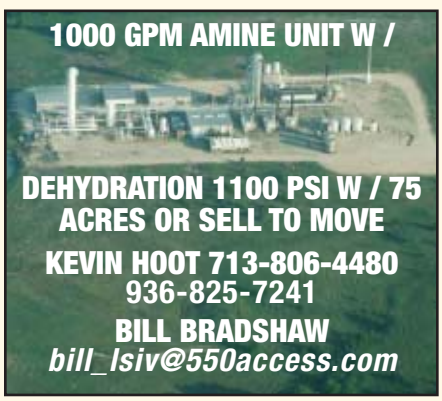

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Treasury: Oil, gas 'overproduction' a threat to security

For oil and gas, the national-security argument has always been a two-edged sword. The back edge now slashes savagely.

US producers see security as a reason to encourage domestic production of oil and gas. Their position makes perfect sense.

But the politics of energy is rarely sensible—less so now than ever.

The Editor's Perspective

by Bob Tippee, Editor

When producers base their policy arguments on security, they traditionally have had in mind the benign goal of lowering US dependence on foreign oil by raising domestic production.

The back edge of the security argument pursues something quite different: lowering dependence on foreign by lowering the use of oil altogether. And one way to lower the use of oil is to produce less.

The back-edge logic undergirds a Department of Treasury report explaining the Obama administration's revenue assumptions in its budget proposal for fiscal 2010.

The budget repeals a series of tax measures crucial to independent producers—especially small producers—such as percentage depletion and expensing of intangible drilling costs. It also denies oil and gas companies of all sizes use of the manufacturing deduction available to companies in other industries since 2004 as a way to help them compete internationally.

In each case, the "reason" offered by Treasury reads like this: "The [measure or its result], like other oil and gas preferences the administration proposes to repeal, distorts markets by encouraging more investment in the oil and gas industry than would occur under a neutral system. To the extent the [measure or result] encourages overproduction of oil and gas, it is detrimental to long-term energy security and is also inconsistent with the administration's policy of reducing carbon emissions and encouraging the use of renewable energy sources through a cap-and-trade program [emphasis added]."

The first slash thus amputates the correlation between domestic oil and gas production and energy security—the front-edge security argument.

If the budget passes, the next lacerations will befall oil and gas production. They'll be deep. Confronted with shrunken access to economically viable energy and the need to pay for costlier alternatives, Americans who buy fuel and pay taxes will do their bleeding later.

(Online May 22, 2009; author's e-mail: bobt@ogjonline.com)

Market Journal

by Sam Fletcher, Senior Writer

Crude tops $62/bbl

On May 20, its first day in the front month position, the July contract for benchmark US sweet, light crudes escalated $1.94 to $62.04/bbl on the New York Mercantile Exchange, marking the first closing above $60/bbl since early November.

Crude futures were spurred past $60/bbl resistance by gains in the equity market, a weak US dollar, and the latest wave of unrest in the Niger Delta, with raids on both oil facilities and militants' camps reported. However, July crude retreated to $61.05/bbl in the next session as major US equity stock indexes were hammered and the dollar gained in value.

Nevertheless, with the Dow Jones Industrial Average down more than 2% and a sharp drop in the price of natural gas, the fact that crude was able to sustain above $60/bbl was "further confirmation that crude oil is starting to have a trading life of its own rather than being a pure correlation to equities that even a 5-year-old could trade," said Olivier Jakob at Petromatrix, Zug, Switzerland.

In New Orleans, analysts at Pritchard Capital Partners LLC said, "On a historic basis at 17 times the price of natural gas, oil is trading way above the historical 7:10 ratio. However, concerns over the dollar and its sovereign credit rating may help crude hold the $60 level provided investors see crude as an alternative to the dollar."

At the Centre for Global Energy Studies (CGES), London, analysts said, "The oil futures market remains buoyant, despite ample oil inventories in the US and Europe and over 130 million bbl of oil stored at sea, while US refinery utilization remains low."

They said, "The current economic situation remains unremittingly bleak—US housing starts in April were at their lowest level since records began, and Japan has posted ghastly first quarter gross domestic product figures." Nonetheless, CGES analysts said, "Global oil demand could be at a turning point, and oil prices will find more support from the fundamentals if there is a stock draw during this quarter, as the Centre expects."

Demand is not nearly as feeble as it was in the first quarter, said CGES analysts. "During this quarter consumer inventories were run down in most industries, causing stocks to rise at the manufacturing or extraction stage, but such a process cannot carry on indefinitely. In the oil market, the secondary and tertiary stocks have been run down so far, and when these come close to tank bottoms a draw down of primary stocks should begin. Indeed, this looks to have already begun in the US," they said.

Meanwhile, the main challenge for the Organization of Petroleum Exporting Countries is to maintain a high level of compliance with the group's official target. "With Nigeria in disarray, other members might well be tempted to make up this 'shortfall,'" warned CGES analysts.

Natural gas

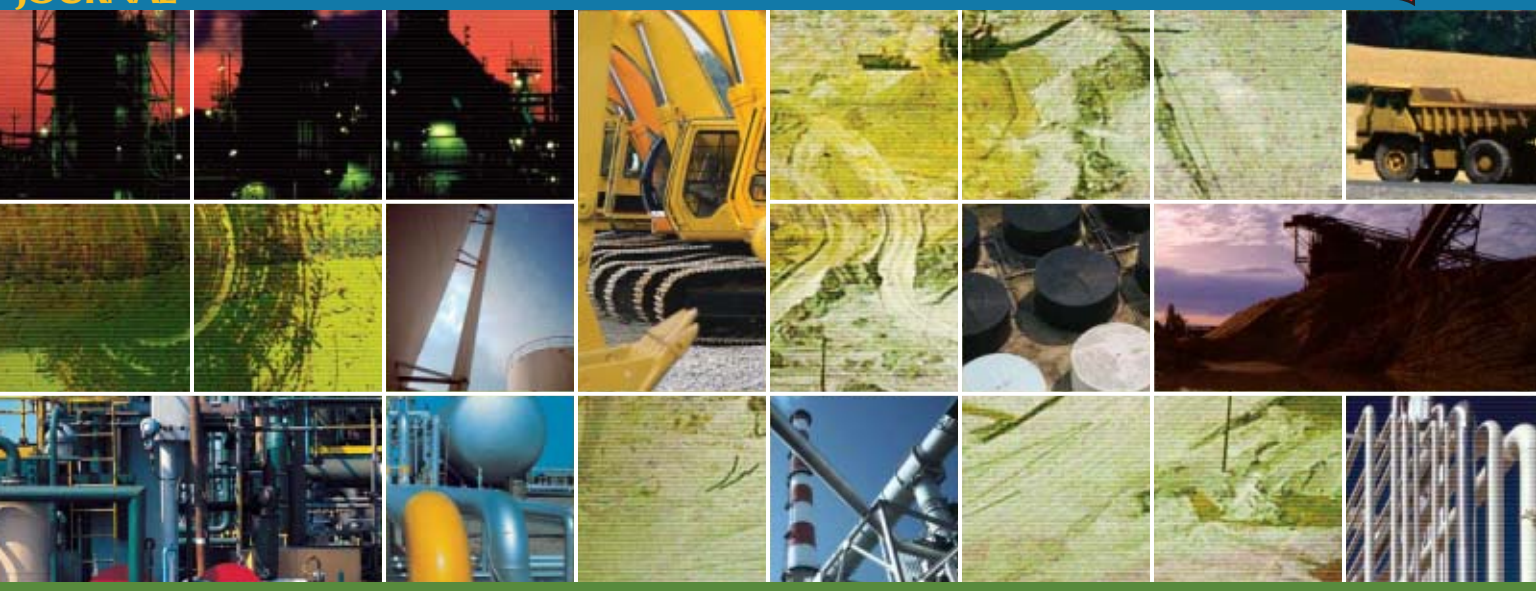
During May 21 trading, analysts in the Houston office of Raymond James & Associates Inc. said, "The real fireworks were in the gas market where prices plummeted 9%"—the biggest 1-day drop in natural gas futures prices since August 2007. That came after the Energy Information Administration reported the injection of 103 bcf of natural gas into US underground storage in the week ended May 15. It put working gas in storage at 2.1 tcf, up 514 bcf from year-ago levels and 387 bcf above the 5-year average (OGJ Online, May 21, 2009).

Raymond James analysts said, "The market is still oversupplied, and the drastic fall in the rig count was most likely too late to save the market from dismal summer gas prices. Be it delayed completions, choking back wells, or completely unplugging the christmas tree, we still believe there will have to be substantial shut-ins this summer."

The drop in gas price appeared "completely trading driven as the price action on the physical hubs was fairly subdued, and approximately half of the hubs we monitor traded up on [May 21] despite the pounding NYMEX natural gas took. The physical markets are not moving in lock step with the NYMEX 'trading' market," said Pritchard Capital Partners. "If the physical markets do not follow the NYMEX market in next few days, the sell-off may just have been a trading event."

Adam Sieminski, chief energy economist, Deutsche Bank, Washington, DC, said, "At prices near $4/MMbtu, the EIA calculates a 2 bcfd gain in gas use in the southeast US. In our view, a gain of this amount is required over the rest of the storage build season in order to prevent a storage peak rising from 3.7 tcf to 4.1 tcf."

(Online May 25, 2009; author's e-mail: samf@ogjonline.com)



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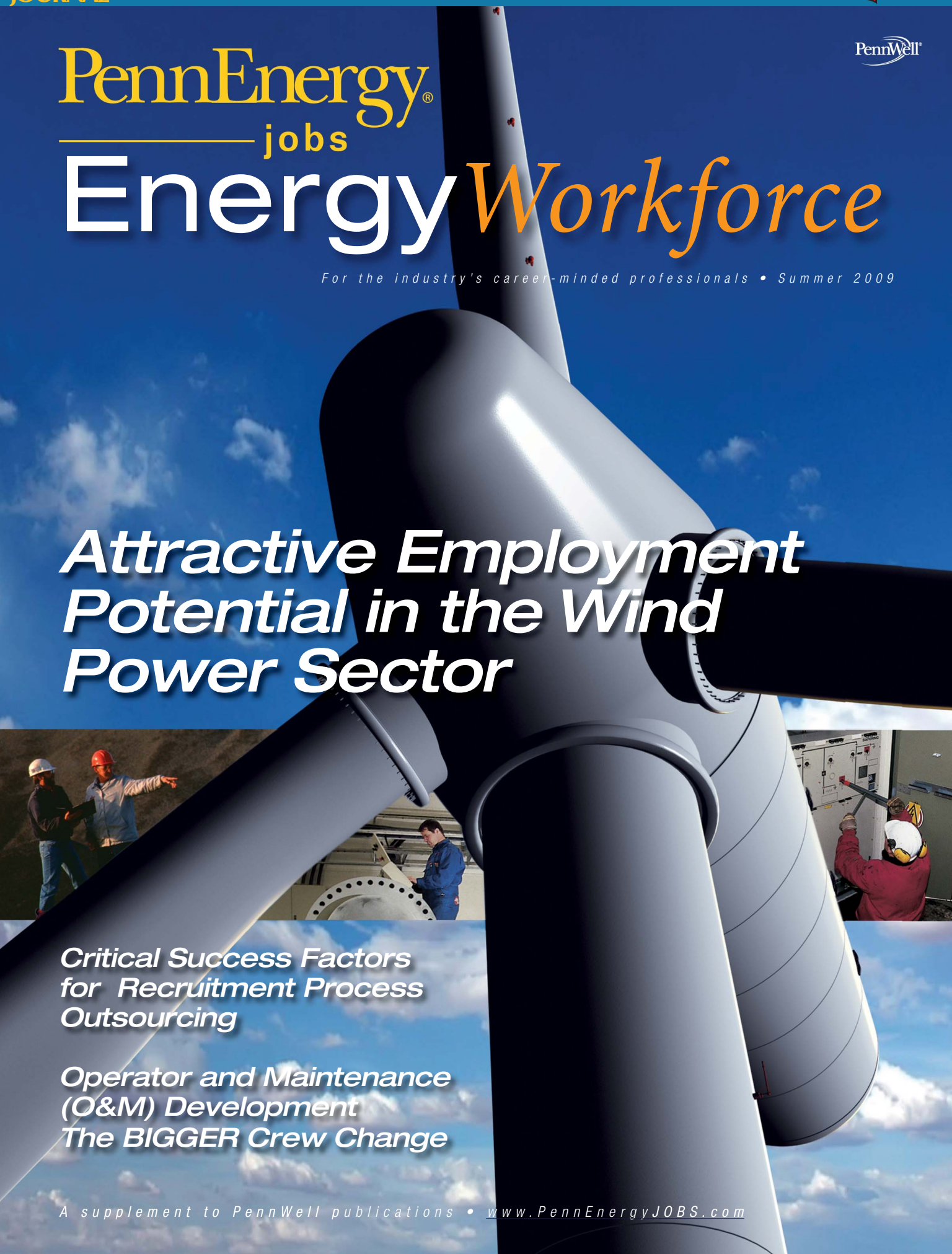

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Human Resource's Strategy for the Future

Forward thinking businesses understand that the time to recruit for the future is today. The competition for top talent is still very much alive and well.

At the outset of the economic downturn, companies responded with a typical reactionary approach. The corporate landscape for 2009 has been rife with layoffs, salary freezes and stalled recruitment efforts in an attempt to "stop the bleeding." Yet, as the recession deepens, and it has, many corporations will face real concern and anguish over cutting costs versus retaining talent. There has never been a more pressing time for HR professionals and leaders to develop a long term workforce strategy for their organizations. Cost cutting is an unavoidable necessity in the midst of a recession; however, retaining, recruiting, and strengthening top talent are all requirements to successfully outlasting a recession.

The leading organizations post recession will be the ones that are able to look beyond the current financial turmoil and identify the competencies they will need in the future. HR professionals and corporate leaders should be working together to define what their future workforce must look like before conducting any more layoffs. Companies that do not first establish a strategy for the future run the risk of not having the right players on board to see them through the recession or compete successfully when the economy turns around.

Just keeping the right staff is not enough. Forward thinking businesses understand that the time to recruit for the future is today. The competition for top talent is still very much alive and well. This is especially true for corporations within the energy industry. The combination of Obama's Energy for America plan, which is expected to create more jobs within the energy sector, and an aging energy workforce, will result in scarce resources. No one can say for sure when the economy will emerge from this recession, but waiting to start recruitment efforts at the tail end means being behind the curve in the competition for talent.

With a limited pool of skilled and educated workers, corporations will have to find alternatives to building a successful workforce. HR professionals taking the long-term view foresee the need to invest in training and development now to build a stronger workforce for tomorrow. The need to organically grow talent combined with the rapidly changing pace of skills and education required within the energy industry suggest that a heavy focus on training be undertaken immediately. Developing the skills of the workforce not only strengthens a company's competitive edge, but also inspires loyalty, organizational commitment, and encourages continued learning for the future.

HR professionals have the opportunity to lead corporations forward not by tactically enforcing operational cost cutting measures, but by developing a long-term workforce strategy.

Sincerely,
Stanna Brazeel,
Manager, Staffing and Salary Administration, Human Resources
PennWell

Attractive Employment Potential in the Wind Power Sector

Among just a few industries today with positive growth and employment opportunities across all global markets is the wind power sector. It has experienced steady growth since 2001-2002 in North America, and for a longer period in Europe where this business got its start. This article provides a brief summary of current and potential employment conditions in this important and growing area of business.

Positive Support for Wind Power Sector

The positive nature of wind power today was validated quite recently by record attendance at the WINDPOWER Conference in Chicago during the first week in May. The number of exhibitors and attendees were both up more than 50% from the 2008 conference held in Houston. The American Wind Energy Association (AWEA) sponsors this and other wind energy-related conferences.

There are several drivers for today's keen interest in the wind power space:

- Continuing momentum in wind farm installations, especially in the U.S.
- Wind turbine manufacturers have smartly managed the 2002-2008 run-up and a 2009 "pause"
- Electric power generated from a renewable sources is needed and will be mandated
- Political support for this space continues, with staying power in Europe and the U.S.
- Stimulus and investment factors are becoming more supportive
- A long-term future underlies the wind space worldwide

In an era of reshaped commerce and business that is evolving today, the wind power space has much predictability for the future and consequent support for current and future employment opportunities.

Wind Power Beginnings

Wind turbines convert kinetic energy from moving wind resources into rotational energy, which in turn is ultimately converted to electricity. Wind turbines are not new; their beginnings go back many years. The early designs for the current, modern wind turbine of today were actually developed by the U.S. Department of Energy through efforts at their National Renewable Energy Laboratory (NREL) in Denver, Colorado. However it was European manufacturers who took those designs, improved them and launched a totally new renewable energy business.

This sector has grown steadily since 2001-2002. The U.S. wind power business started with the import of turbines, equipment and technology from Europe. But there is now steady growth opportunity in the U.S. for domestic equipment and component manufacturing, parts and supply, contract construction and ultimately, attractive employment possibilities.

Employment Opportunities

Wind power employment typically falls into three segments: wind turbine manufacturing, wind farm construction & development and electric power delivery.

Wind Turbine Manufacturing — The majority of wind turbine manufacturing capacity today is sited in Europe. But thanks to huge wind resources across the mid-section of the U.S. there has been significant growth in U.S. turbine installations. More than eight new wind turbine manufacturing plants were opened in the U.S. in 2008 and another 19 facilities announced. In total, during the 2007-2008 period there were 70 new facilities announced, added or expanded in the U.S. with 55 of the total being manufacturing locations (most were European).

There has been significant support and investment by European manufacturers in U.S. wind power. A good example is a recently-opened wind turbine manufacturing facility in Brighton, Colorado owned by the Danish firm Vestas, the world's leading wind turbine manufacturer. Vestas is also planning a 400-employee factory in Pueblo, Colorado to build towers that support these wind turbines. It's estimated that about 50% of all components for U.S. wind turbine installations are now manufactured in the U.S. with that share increasing steadily.

What kind of occupations are there in wind power manufacturing? A recent study that included a 250-employee wind turbine manufacturing facility identified a surprising 126 occupations, ranging from manager to engineer to machinist, technician and even janitor.

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Wind Farm Construction & Development — Wind farms are the heart of the business and are installed ideally where there are high-velocity wind resources ("resources" mean the wind is predictable and strong, as opposed to being intermittent and unpredictable). The total U.S. wind resource base includes a broad sweep of the area in the U.S. from West Texas through the Dakotas, also encompassing areas of the Rockies.

Developers of wind farms are similar to real estate developers, in that the economics of a facility must be attractive over time to warrant the investment, construction and operation of such a facility — in this case a wind farm. Today's typical wind farms may have 100 to 300 wind turbines installed and could cost from $1.4 million to $3 million per installed turbine (includes all land and infrastructure). A development team for such a facility will include meteorologists, real estate/land procurement personnel, engineers, environmental permitting staff, financial analysts, wind technicians and highly-qualified engineers. All this to determine feasibility, secure financing, plan, engineer and construct the facility.

During the construction phase, there are requirements for construction and installation personnel, lifting/rigging equipment & cranes and ultimately, testing and startup specialists. Constructing today's wind farm will be a four-year process from planning to startup. It should be noted that there is significant site research and detailed collection of data to validate the site in terms of wind resource, overall economics, satisfaction of permitting & land use regulations, funding, land owner negotiations & permission, etc. The front end of these projects can be critical in terms of wind farm "capacity" or uptime, which can range from 30% to 40%. A capacity shortfall from plan of 1% or 2% can be a killer in the economics of a wind farm.

But it doesn't stop there. Just as in other productive installations with equipment running on a constant basis, there are operations and maintenance (or O&M) requirements for the facility that will extend throughout the next 20 - 30 years. Truly, wind farm installations are quite similar to power generation, petroleum processing or other types of plant installations in the way they are conceived, planned constructed and operated over their lifetimes, and have a similar employment requirements and opportunities to those types of facilities.

Electric Power Delivery — Employment opportunities here are transitioning into the electric power generation sector which also includes the electric power grid. As wind farm installations are added across U.S., European and other geographic areas, there is the dilemma of transporting electric power from areas with high wind resources (typically less populated) to high-demand areas (typically with large populations). Thereby, the existing electric grid system of today is challenged. Additions must be made, and that will be a part of the future employment opportunities as the electric power sector will enhance and extend to the existing grid.

Employment opportunities in this segment of wind power will most often be categorized as planning, engineering, financial, construction, line maintenance, etc.

Employment in the Wind Power Sector

According to *Renewable Energy World Magazine*, the European wind power sector had direct employment of almost 109,000 by the end of 2008. This is more than twice the sector employment in 2002 and represents an annual increase of over 12,000 jobs per year. If we add indirect employment of 50% (to include various supply, legal, accounting, financial services professionals, etc.) then total indirect plus direct employment exceeded 160,000.

In the U.S., wind power is now considered a mainstream option for electric power generation, and just slightly behind Europe in employment. AWEA estimates 2008 employment in the wind sector at 85,000 jobs. According to the new U.S. Administration, initiatives extended to renewable energy (that include production & tax credits, training, outright grants and other support) would be sufficient to grow the business so that by 2030 there could be approximately 500,000 jobs in the overall renewable space. That is quite a jump for a 21-year period, but this sector now has momentum supported by politics, financial realities and more attractive economics.

What's Ahead

Most important, right now there is life in the current wind sector employment scene with a broad range of openings continuing to be advertised. Some examples of help-wanted advertisements dated 13th May 2009:

- ***Turbine Manufacturer*** — Currently seeking qualified staff for openings in Engineering, Quality Control, Production Engineering, Field Operations and Technical Training
- ***Turbine Installer*** — Looking for Site Project Managers, Site Project Engineers, Site Safety Managers and Field Superintendents

- ***Electrical Contractor*** — Seeks Wind Energy Electrical Technicians and Supervisors
- ***Crane & Rigging Company*** — Looking for Site Managers and Project Managers
- ***Renewable Energy Consultancy*** — Recruiting for Senior Electrical Engineer, Turbine Engineer, Senior Project Manager and Meteorologist

Although there is a worldwide pause in overall manufacturing and installation of wind power capacity at this time, it is largely due to credit and financial markets seizing up and not necessarily because of the economics that drive this business in "normal" times.

The good news is that this sector is receiving political support and financial incentives to grow and employ workers — and fast. In addition, the turbine manufacturers have managed this current "pause" for installations quite well, so there is minimum clogging of the supply channel for wind turbines, which could otherwise negatively impact manufacturing activity in 2009 and 2010.

In summary, our perspective for the wind power sector and its related employment opportunities is positive, with potential for uptrending activity by late 2009 or early 2010. The commitments of financial stimuli, tax breaks and government investment in this sector along with now-realistic economics of wind power will be hugely supportive in both the near term and in future years. *—EW*

About the Author

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- Results oriented with an ability to devise and manage a portfolio of projects/activities, ensuring delivery and results;
- Excellent interpersonal skills and ability to establish relationships at the highest level with government and industry;
- Ability to lead, work independently and to participate in multi-disciplinary teams;
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Critical Success Factors for Recruitment Process Outsourcing (RPO)

As the industry landscape for energy and power changes, addressing key workforce-related challenges is a critical issue for organizations looking to gain the competitive advantage. Take for example the following statistics:

- According to its March 2009 Report, the Energy Information Administration (EIA) predicts that approximately 259 gigawatts of new generating capacity will be required between 2007 and 2030. *(Significantly increased capacity)*
- The total wind power generating capacity jumped by 50% in 2008, according to the American Wind Energy Association (AWEA). *(Increased diversification in power generation)*
- Nearly one half of the U.S. power worker population will be retirement eligible within the next five to ten years according to Carnegie Mellon University's Electricity Industry Center. *(Increase in workforce demand)*
- According to a 2006 report from Booz Allen Hamilton, the number of students studying petroleum engineering dropped to about 1,700 in 17 U.S. universities as compared to over 11,000 in 34 universities in 1993. *(Decrease in workforce supply)*

It's no wonder then, considering these troubling supply/demand ratios, that talent acquisition has taken on a newfound significance as a key organizational competency. Recruitment Process Outsourcing (RPO) can be a vital tool for talent acquisition, staffing, and recruiting leaders to succeed in this challenging environment.

The following best practices and benchmarks discuss how to leverage RPO to gain a strategic advantage.

Planning and Setting Goals

Recruitment Process Outsourcing can refer to the entire recruiting process or key elements of it. As organizations are under intense pressure to continuously improve business execution and refocus on their core competencies, they must objectively evaluate the components of the recruiting process and determine what they do best internally, and what should be outsourced to an expert third party. A thorough due diligence is required to carefully weigh and compare various product and service options, contract terms, pricing scenarios, efficiencies gained, and results achieved with the third party options as compared to maintaining these interventions in house.

When it comes to goal quantification, many organizations rely too heavily on metrics related to a technology-enabled talent acquisition function, including time to fill, cost-of-hire, and total number of open positions. A common theme with these measures is that they are all internally focused on the recruiting function and do not consider post-hire metrics associated with actual on-the-job performance, and the specific needs of the business. Therefore, an important part of the goal setting process is to engage business line leaders and strategic planners in a discussion about the business impacts they find most crucial. Coupling the recruitment function goals with the business unit goals will provide a more holistic set of objectives for the recruitment outsourcing program.

Three best practices for goal setting to consider are:

Optimize Workforce Planning

To maximize the effectiveness of the client-RPO vendor relationship, the process needs to begin further upstream so as to consider not only the short term but the long range recruiting requirements. With vast infrastructure projects on the horizon, and the emergence of new power subsectors, coupled with projected labor shortfalls, some organizations need to plan for hundreds if not thousands of new hires. This undertaking is highly complex, takes a significant amount of resources, and must be tightly choreographed. Therefore, recruiting leaders must partner with human resources, strategic planning, business line management, and RPO partners to ensure process integrity and strengthen the recruitment supply chain. Only with tight integration and strategic business planning will workforce planning be optimized. Key components of

this process include: a forecast of future labor requirements predicated on growth plans, new products and services, and technology and infrastructure build outs; the development of competency models to identify the specific talent requirements needed to support these initiatives; a determination of where skill and talent gaps exist in consideration of both new competencies and retirement and turnover; and the identification of RPO channels, resources, processes, and interventions required to source the needed talent.

Develop Recruiting and Business Metrics

The most impactful metrics are those derived from an assessment of both the business requirements and opportunities for process efficiencies, and those based on high integrity baseline measures. By engaging business line leaders, talent acquisition managers can meld the business and recruiting goals and prioritize the most important metrics. For example, field operations may be most interested in decreasing the time spent by their hiring managers in the recruiting process. Service center directors may be primarily concerned with reducing the total number of open positions within their centers. Headquarters executives may see time to fill strategic positions, as a critical measure and area for improvement. Those hiring sales personnel or knowledge workers may be looking to improve speed to task / competence / revenue. HR leaders may have a vested interest in meeting compliance requirements, streamlining processes, reducing costs, and outsourcing key components of the recruiting process to best-of-breed vendors. Out of all of the measures, perhaps two of the most common are increasing retention and reducing cost-per-hire. According to the Aberdeen Group Report *RPO in 2009: Driving Cost and Quality Improvements*, those organizations deemed best-in-class were able to cut cost-per-hire nearly in half (48%) through use of RPO.

Once the set of measures is determined, recruiting leaders will be well-positioned to determine the type of RPO providers best able to meet the organization's strategic requirements.

Diligently Market the Employer Brand and Become and Employer of Choice

As a vast cross section of the energy and power workforce reaches retirement eligibility, new college graduates become fastidious in their career / employer choices, and the overall global labor market tightens—combined with projected rapid growth within utilities, oil and gas, and alternative energy sectors—organizations must become very adept at promoting their employer brand. Much like product marketing, recruiters must effectively promote the employer brand, enhance name recognition, and educate candidates on the organization's market position and presence, corporate culture, and differentiators. Employer branding practices must extend to all candidate touch points, resonate effectively through the recruiting channels used by the target audience, be leveraged across all RPO partners, and be consistently reinforced.

Making Wise Recruitment Process Technology Decisions

To support the process of attracting and retaining high-quality talent, progressive organizations are evaluating or re-evaluating their recruitment process technologies. In selecting both a best-fit partner and the best-fit application, there are three important trends that energy and power organizations should note.

First, the recruitment process technology industry continues to undergo significant consolidation, making it perplexing and potentially risky as a buyer. Secondly, more and more companies in this industry are focusing their efforts on integrated talent management suites as opposed to talent acquisition systems. Finally, with many vendors, there is a greater focus on new system components rather than on ensuring the quality of hire. These trends are highlighted in terms of greater service, improved reliability, and wider reaching automation; but do these 'benefits' best meet end-customer requirements? For organizations with the budget and time commitment required to implement a full talent management suite, or who wish to work with the largest market share providers, the answer may be yes. For many others, the answer requires further consideration.

"Much like product marketing, recruiters must effectively promote the employer brand, enhance name recognition, and educate candidates on the organization's market position and presence, corporate culture, and differentiators"

As the RPO industry consolidates, acquiring companies are looking to reduce operating costs, quickly penetrate new markets, and add on components to their talent management solutions. It is not unusual for key product and industry experts from the acquired company to leave the organization and take with them the accumulated knowledge and expertise they possess. In many instances, the acquired product is added

to a portfolio that is only marginally related to the acquired company's original core competency. The movement towards offering integrated talent management suites is based on the perceived benefits of integrating multiple HR processes, placing the emphasis on software—as opposed to the interventions that help acquire top talent.

For organizations focusing on talent acquisition, the buy- side implications of these trends are clear. With the increased number of consolidations, there are less 'brand-name' options available. The cast may change, product expertise may be diluted, and support and migration options may be limited. Purchasing a fully integrated talent management suite will require a greater budget allocation, and can result in lengthy multi-phased implementation cycles. It could also mean delaying the purchase to re-evaluate priorities and cost justify the larger application. If the objective is to effectively recruit, identify, and hire top talent—it could mean a long and winding path with no end in sight.

> *"With stiff competition for top talent among energy and power companies, as well as from other industries, retaining this talent becomes a critical concern"*

For those who require a talent acquisition solution that enables them to compete for top talent now, there are viable options, but making the best decision requires careful consideration. When considering best-of-breed talent acquisition solutions:

- Assess the configurability of the solution to support the recruiting workflow and meet both current and future requirements
- Determine if the vendor utilizes validated assessments to ensure quality of hire (a critical but often underemphasized consideration)
- Ascertain the organization's expertise in delivering measurable impact through better hiring decisions
- Inquire about potential mergers and acquisitions the vendor may be involved with, and about their financial status
- Stand firm on the established requirements and guard against being oversold on unneeded functionality

Ensuring Quality of Hire

With the current economic downturn, it is easy to assume that there is an abundance of high quality talent for the taking. While that may in part be correct, there is also a lot of talent that may not be well-suited for an organization's current and projected talent requirements. And the business impact as a result of poor talent fit can be quite significant.

Retention considerations

With stiff competition for top talent among energy and power companies, as well as from other industries, retaining this talent becomes a critical concern. Consider these statistics: The direct and indirect costs associated with premature turnover average around $3,500 per employee for non-exempt positions according to the Society of Human Resource Management. Research from The Center for Creative Leadership has shown that 66% of Senior Management hired from outside a company fail in their first 18 months. And according to the Bureau of Labor Statistics, the average tenure for 35-44 year olds is declining.

Ethics and Counterproductivity Risks

The direct costs of a bad hire relating to ethical misconduct, employee theft (including identify, intellectual property, and physical assets), lost sales, workplace accidents, as well as the indirect costs associated with reputation and brand erosion are significant. Researchers have found that in times of economic uncertainty with mounting financial pressures on job candidates and employees, these risks are exacerbated (85% of business ethics and compliance professionals indicated that the current economic downturn materially increases the risk of ethics and compliance failures according to the Healthcare Compliance Association and Society of Corporate Compliance and Ethics, 2009). The National Institute of Drug Abuse cites that employees at risk for illegal on-the-job substance use have been shown to have three times more sick days, three times the tardiness rate, three times more accidents, and are five times more likely to file workers' compensation claims than individuals not engaging in illegal substance use ($1,500 average cost per drug-using employee).

Achievement of Strategic Imperatives

As organizations pursue high-value activities in order to gain a competitive advantage, it is critical that talent is properly aligned with these activities—talent with the right mix of knowledge, skills, abilities, and personality traits. While on an individual basis, mis-hires may not appear to have a strategic impact, on the aggregate, they may have negative and lasting consequences related to lost business opportunities, decreased morale, strategic misdirection, poor service, and ethical lapses to name a few.

The problem with many existing employee selection approaches is that they rely too heavily on subjective methods of evaluating talent. In order to best ensure that top talent is selected into the organization, recruiters must incorporate an objective means of assessing talent. A critical RPO product that offers this objective evaluation is validated talent assessments. Vangent's research has found that when utilizing (its) validated assessments, significant and strategic impact can be achieved (e.g., turnover—33% drop, tangible theft—23% reduction, Return on Investment (ROI)—12:1 ratio, workplace accidents—23% decrease, and accident costs—31% drop in average costs incurred due to accidents).

When evaluating assessment providers consider the following:

- Are assessments the core competency of the provider?
- Are the assessments documented to be valid and reliable selection instruments?
- Have the assessments demonstrated meaningful ROI?
- Can the assessments be mapped to existing core competencies?
- Can the assessments be utilized within an existing applicant tracking system?
- How does the assessment provider keep current with regulatory compliance requirements?
- Is the assessment provider a member of a reputable industry association, and do they adhere to the association's standards and guidelines?

Taken together, these ideas can help form a framework for a Recruitment Process Outsourcing program. While each RPO situation is unique, RPO products and relationships—like any other strategic decision—requires careful due diligence. And as these relationships are strategic, an overarching goal should be to engage the RPO provider not as simply a vendor, but as a critical supply chain partner. —EW

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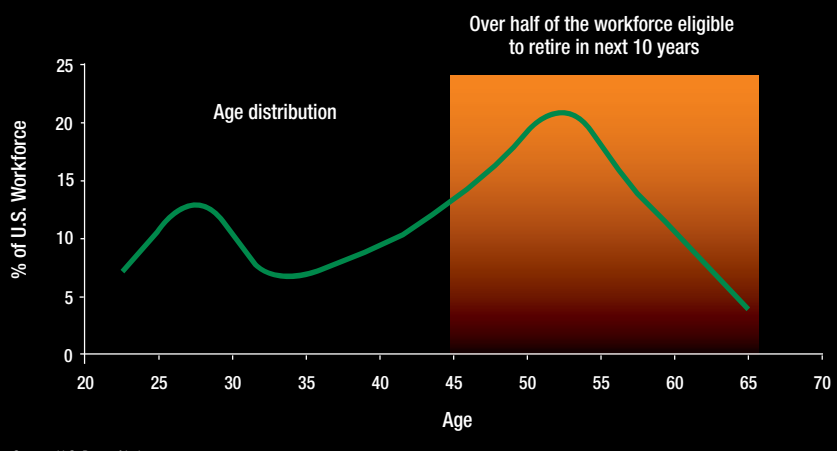
Operator and Maintenance (O&M) Development: The BIGGER Crew Change

O&M Challenge

Significant attention has been given within energy publications to the impact of the of the "big crew change." Many articles speak of the change that was to come; today, we find it to be finally underway. Within the professional engineering ranks, crew change demographic numbers are stark and well reported. Corporate and academic efforts have been launched to address this challenge. What has not been as well discussed or addressed however is the significantly ***larger or Bigger*** crew change taking place within the operations and maintenance (O&M) discipline. The purpose of this article is to communicate the attributes and possible solutions to the industry's current O&M crew change challenge.



Source: U.S. Dept of Labor

If one looks within the operations and maintenance side of the business - where front line workers actually turn valves, monitor pressures and temperatures, start and stop equipment, and maintain production within expensive assets - industry demographics are as bad or worse than those of the technical professional ranks. Senior plant operators with hard-won, pivotal, real time problem-solving knowledge are disappearing as the baby boomer demographic begins to edge into retirement. They move on to their fishing boat, horse farm, small business, or to the tuning of equipment on their favorite classic car.

Having been "spoiled" by a twenty-year supply of highly trained, well qualified senior personnel, the industry and its ability to "grow" new operators has waned. 21st century O&M feedstock (aka, "potential new hires") often lacks the solid, mechanical, hands-on-based skill sets seen in their generational predecessors. Additionally, potential new hires are often faced with career paths that require relocation across the globe. New facilities can be located near the "harder to find" resources in remote regions of the Middle East, Africa, Latin America, the "Stans," and Asia, either onshore or offshore. Nationalization programs by the NOC's and contract obligations placed upon the IOC's within numerous countries require that the preferred supply of new operator technicians stem from the local populations. Many new employees enter a process or chemical plant for the first time, having no related mechanical or operator skills.

Finally, if one considers the typical makeup of the workforce in both field and plant operations worldwide, one would find a healthy supply of expats in senior positions. It is on the shoulders of these operator technicians where much of the responsibility for critical operations and stable production relies. As the generational and cultural handover of knowledge to a younger, less skilled, crew begins, the risks to asset integrity and production rises. The oil and gas industry is versed on what can happen when less than skilled operators are at the panel, and a process upset cascades into an uncontrolled event. These losses make a downturn in oil price or the economy collapse appear warm and cuddly.

Some might say that "new technology" will solve many people problems, that "smart systems don't need people to be as experienced to operate them properly." Certainly there is some amount of truth to this point. However, note that while normal operations will be less demanding, the application of new technologies has historically meant additional training

requirements for maintenance, troubleshooting, turnaround, etc. New technology drives a need for different, and normally, *more* technically demanding skills.

One recent example of this is that automation on drilling rigs has actually increased both the skill and number of personnel required. Operations are much more efficient and effective, but lowering the skill – or even number – of workers has not happened. Automation definitely means that fewer people are required to move pipe, but an even higher level of skilled technicians is necessary to keep systems working properly. Even with "robot" operators, someone needs to fix the robots.

Understanding the Challenge

So how does a company go about replacing and developing a cadre of operator and maintenance personnel? The answers are not easy. Developing skilled O&M personnel takes time and diligence, even under the best of circumstances. Given today's changing O&M demographic and workforce nationalization demands, the challenge becomes even more difficult.

The process of training O&M personnel versus newly hired engineers has unique challenges. For instance, annual per capita training budgets average $4K/employee, often less than half the amount set aside for technical staff. This is further amplified when one understands that the knowledge and skills required by any one job posting is fairly site- and plant-specific, with a clear need for mentoring, coaching and hands-on rounds and routines. Corporations individually address the competency challenge under their responsible care, HSE, and process safety management regimes, but they have often lacked a consistent sustainable program or best practice. Globally, the industry has been unable to create and maintain a standardized approach to the challenge of operator and maintenance technician training successfully. To be sure, there have been a number of well know regional approaches and organized bodies that attempted to address the skill development and transfer of knowledge to new technicians. Often these approaches are coupled with a form of "certification." To date, no global industry O&M training effort has emerged.

Differing Approaches to Meet the Challenge

Industry has, often belatedly, settled on one of four broad approaches to addressing challenges of these types: "Business-as-Usual," "It's-the-Asset's-Problem," "Corporate-Solution-Initiative" ("CSI"), and "The-Co-Op."

The ***Business-as-Usual*** approach would really be more appropriately named the "Do Nothing" approach. Many operators - from our experience on the order of 33% - have yet to realize fully the urgency and importance of the big crew change. They have no reliable program in place to develop the next generation of O&M personnel. This approach does have the advantage of being cheap – and perhaps these organizations will be able to hire personnel away from others who do develop personnel. Certainly, this approach is fraught with organizational and operational risk.

Companies choosing the ***It's-the-Asset's-Problem*** approach do recognize the challenge and do proactively allocate resources to develop the next generation. Organizationally, they chose to do this on a plant-by-plant, or area-by-area basis as needed. This allows for development expenses to be allocated to the operational level, usually only when the local situation warrants. This approach can be effective, but risks include a lack of uniformity in standards, competencies, and training methodology. Ultimately, this approach can result in higher total development costs associated with duplicative efforts between business units.

"Industry has, often belatedly, settled on one of four broad approaches to addressing challenges of these types: "Business-as-Usual," "It's-the-Asset's-Problem," "Corporate-Solution-Initiative" ("CSI"), and "The-Co-Op."

The ***Corporate Solution Initiative*** or ***"CSI"*** approach is characterized by an organization taking a corporate-wide approach to building (or in many cases *rebuilding*) development programs for O&M personnel on a global basis. This normally is a more cost-effective way to create reliable and consistent development programs than working asset by asset. A new approach, the Co-Op approach, offers even more advantages, while simultaneously reducing risk.

The Co-Op approach represents an industry alliance characterized by a number of companies working together to develop a common development framework. This framework takes the form of a competency map library and common approaches for development-related activities. This allows organizations to focus their resources on what's unique and to

leverage costs and experiences from other Co-Op members to reduce the costs of building and maintaining CSI-type development programs.

These cost reductions (compared to the CSI-type efforts) are not insignificant; for example, if ten organizations work together as part of a Co-Op, since they share development costs, savings of up to 90% are possible on common skills. Any unique skills training will need to be developed by each organization or asset, but leveraging development for common skills can bring huge benefits. By freeing up the organization to focus on unique skills, it is also possible that the time to solution can be reduced.

The Co-Op approach allows members to work to apply lessons learned to build de facto standards for addressing the O&M challenge, and it allows for the sharing of resources so that world-class development approaches and tools can be applied at a much lower cost.

"The Co-Op approach allows members to work to apply lessons learned to build de facto standards for addressing the O&M challenge, and it allows for the sharing of resources so that world-class development approaches and tools can be applied at a much lower cost."

One example of how a cooperative effort functions may be seen when using an industry advisory board as a steering mechanism, when member companies are working to contribute to and have access to a common "competency library" consisting of competency maps (or "CMaps") for areas such as gas process operations, field process operations, refining, offshore production, etc. These CMAPs are linked to the content libraries for operator technicians.

Co-Op Example – SAIT and Trinidad

SAIT, a PetroSkills partner, is a world leader in skilling new operators. SAIT has demonstrated unique methodologies and technologies for building physical facilities worldwide. SAIT's knowledge libraries include more than 2,000 technical training modules that have been developed with the support and input of the oil and gas industry over the last 35 years. The modules, known as "SOLIS," became a standard for operator technician training in Canada. In recent years, SAIT worked with various organizations including the government of Trinidad and Tobago to give birth to the Trinidad and Tobago Institute of Technology (TTIT) which was later subsumed to become the University of Trinidad and Tobago (UTT).

The SAIT-TTIT/UTT relationship began in 1998 by providing a variety of services including the licensing of technical training modules; a field survey for the design and specifications of the National Energy Skills Center (NESC); a training needs assessment; long-term strategic planning to develop an implementation plan for the NESC training center; classroom instructor support; and curriculum development. The year 2003 marked the convocation of the first graduates (120 individuals) from TTIT. Thousands of students since have been enrolled into the different programs.

Leveraging Technology

One other way that Co-Ops are useful is in leveraging the cost of developing new technologies such as alternate methods of immersive training for operators. The technology of virtual reality and virtual environments are reaching a maturity point where cost and effectiveness combine to support breakthrough approaches. In terms of what works, one must thank the billion dollar gaming industry's progress in virtual environments development. These engines are being refocused to address business-critical training serious games. Most expect that when boarding an aircraft, the airline pilot had hours and hours of virtual simulation before ever attempting to fly a commercial liner. Imagine mandatory process operator training programs for new operators which see them climb into a virtual reality machine. They actually *explore the plant*, starting, stopping, and lubricating equipment without the risk of a real process upset. The have the opportunity to *experience* the consequences of their actions and any missed steps or mistakes. By partnering with best of breed solutions across the entire spectrum of learning, development, and training, the oil and gas industry is reaping serious benefits and breakthroughs for the operator crew change challenge.

Technology Example – Fast Procedure Capture

Technology is never the only answer, but it can be applied to close the crew change skill gap in a more rapid fashion. Work by PetroSkills with an IOC used innovative capture technology within West Africa in an effort to reduce time in capturing the knowledge and experience of senior expats. The project converted know-how from the minds of senior expats into an explicit and shareable form.

In total, 800 procedures were compiled over a five month period. When compared to the typical process of the senior

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New Orleans, Louisiana USA
Website: www.ogmtna.com

Unconventional Gas International Conference & Exhibition
September 29 – October 1, 2009
Ft. Worth, Texas USA
Website: www.unconventionalgas.net

Offshore Middle East Conference & Exhibition
October 27 – 29, 2009
Manama, Kingdom of Bahrain
Website: www.offshoremiddleeast.com

Deep Offshore Technology International
Conference and Exhibition
November 3 – 5, 2009
Monte Carlo, Monaco
Website: www.deepoffshoretechnology.com

Deepwater Operations Conference & Exhibition
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Galveston, Texas USA
Website: www.deepwateroperations.com

Oil & Gas Maintenance Technology Conference & Exhibition
Co-located Pipeline Rehabilitation and Maintenance
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Manama, Kingdom of Bahrain
Website: www.oilandgasmaintenance.com

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Website: www.pipeline-rehab.com

Deep Offshore Technology
International Conference and Exhibition
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Houston, Texas, USA
Website: www.dotinternational.net

Subsea Tieback Forum & Exhibition
March 2 – 4, 2010
Galveston, Texas USA
Website: www.subseatiebackforum.com

Offshore Asia Conference & Exhibition
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Offshore West Africa Conference & Exhibition
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Montréal, Quebec, Canada
Website: www.wecmontreal2010exhibit.com

expert sequestering him or herself to sit down and write the procedure using MS Word and a laptop, the time saved was order of magnitudes quicker. Operators remained at the plant "on shift" and were integrated into a process methodology that rapidly captured their knowledge of procedural steps. The operators were shielded from the actual writing process, but were able to provide their deep understanding and insights. Their skills in verbally describing the complex sequences and series of steps in varied process conditions provided the base framework of knowledge from which an accurate transcription could be completed. Procedure writing time shrank dramatically because operators were able to concentrate on those tasks in which they held deep skill sets; namely, espousing their know-how orally.

Summary

This O&M crew change is well underway. By combining industry cooperation, advances in technology, and process consulting, the challenge of creating a globally standardized approach to rapidly skilling and growing competent operator technicians will be achieved. Building this organizational capability is an imperative, given the changes in workforce demographics that will occur over the next decade. The Co-Op approach, wherein an industry competes openly in its unique areas of specialization and advances but collaborates on important industry challenges like training, will aide in answering the Crew Change challenge. —*EW*

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