Week of June 4, 2007/US$10.00

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OIL&GAS JOURNAL

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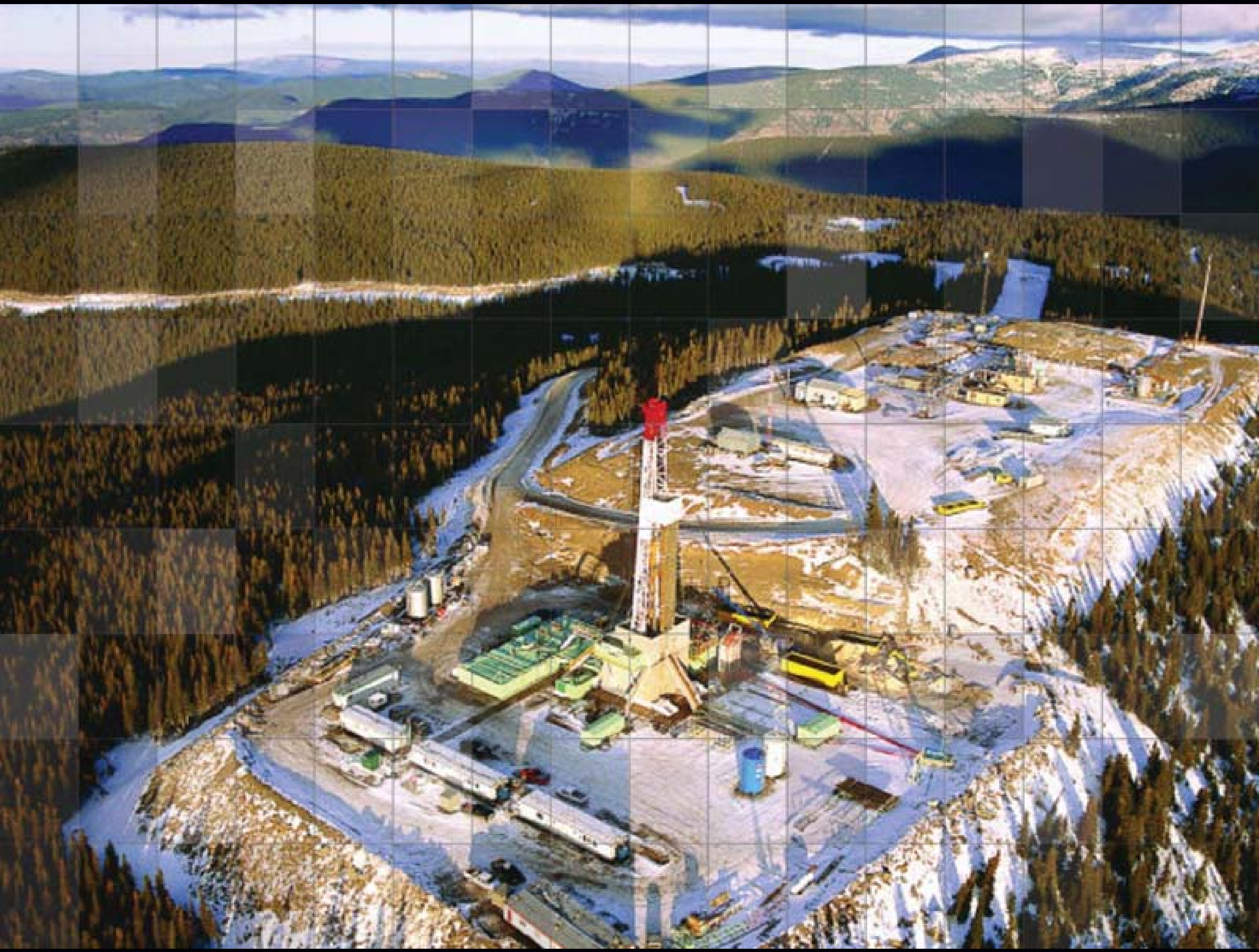

New Views of the Subsurface

Downstream mergers, capacity hikes persist
MPD improves drilling rates in Canadian field
Saudi Aramco installs new LPG recovery unit at Yanbú refinery
Iran details LNG liquefaction plans

OIL&GAS JOURNAL
June 4, 2007
Volume 105.21

NEW VIEWS OF THE SUBSURFACE

REGULAR FEATURES

COVER

A Precision Drilling Co. rig drills for the former Burlington Resources Canada, now part of ConocoPhillips, at Tumbler Ridge near Chetwynd, BC, in late 2005. This area lies in the Foothills Domain, one of six domains interpreted as being part of the structured belt of the Western Canada Sedimentary Basin. The author suggests that the structured belt may contain several hundred trillion cubic feet of recoverable gas in conventional and nonconventional plays. A four-part article on the structured belt interpretation starts on p. 36 in OGJ's New Views of the Subsurface special report. Photo courtesy of Precision Drilling.

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General Interest

Exploration & Development

Drilling & Production

Processing

Transportation

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General Interest — Quick Takes

Oil worker kidnappings continue in Nigeria

Nigeria's ability to defend international oil operations came under scrutiny again May 25 when local militants kidnapped six foreign oil workers—including three Americans—from a pipelaying ship owned by Texas-based Transcoastal Corp. under contract to Nigeria's Conoil.

Shots were fired during the abduction, which occurred off the coast of the Niger Delta near the Brass oil export terminal. According to industry sources, the Americans, two British citizens, and one South African were abducted by the militants who used two speed boats in the attack.

The attack on the Transcoastal ship follows earlier warnings about the increase of piracy off the coast of Nigeria. In April the International Maritime Bureau said that oil tankers and installations off Nigeria continue to be a main target of pirate attacks, despite a downward trend elsewhere around the globe (OGJ Online, Apr. 30, 2007).

Coming just a day after gunmen kidnapped a Polish engineer near Warri, the Brass raid brings the number of hostages now held by militants to 22. The upsurge in violence over the past 18 months continues to depress production by nearly 1 million b/d, or 25%.

On May 15 Royal Dutch Shell PLC said it had been forced to cut 170,000 b/d of oil production after villagers demanding money occupied a major pipeline, bringing the total shut down through unrest, sabotage, and militant action to 980,000 b/d, nearly a third of Nigeria's 3 million b/d capacity.

The Shell shutdown is apparently unrelated to raids by the Movement for the Emancipation of the Niger Delta that took place earlier in May. At the time, Chevron shut down 15,000 b/d of oil production after one Nigerian sailor was killed and six foreign oil workers were kidnapped by members of MEND, who May 1 attacked the company's Oloibiri floating production, storage, and offloading vessel off southern Bayelsa state (OGJ Online, May 2, 2007).

Industry unclear about Colorado landowner law

Colorado Gov. Bill Ritter on May 29 signed legislation that promoters said clarifies the structure for negotiated compromises between oil and gas companies and surface landowners.

The Oil & Gas Accountability Project (OGAP) of Durango helped write the law, which it called "precedent-setting legislation that is one of the most powerful state laws in the nation in terms of protecting landowners' rights and the environment."

An OGAP news release said the law means landowners can require directional drilling of multiple wells from one pad. However, the law itself makes no mention of directional drilling.

The law calls for a "reasonable accommodation" regarding "oil and gas operations in a manner that accommodates the surface owners by minimizing intrusion upon and damage to the surface of the land."

Greg Schnacke, executive vice-president of the Colorado Oil & Gas Association (COGA) in Denver, said oil and gas companies are unclear about exactly what the new law will mean to industry.

COGA statistics show that more than 80% of drilling permits filed in the state already are accompanied by a negotiated surface agreement, Schnacke noted.

"Nobody has ever called a surface owner protection bond," Schnacke said, adding that Colorado oil and gas companies already maintain good relationships with surface owners.

"The concept is an attempt to put into statute what generally already is occurring today. You always are liable for negligence," Schnacke said, adding that COGA expects someone probably will file a lawsuit stemming from the new law.

DOE awards $22.7 million for basic solar research

The US Department of Energy recently announced $22.7 million in funding over 3 years for 27 solar energy research projects that will be conducted by universities and national laboratories in 18 states.

DOE Undersecretary for Science Raymond Orbach said the projects are part of an "aggressive basic research in the physical sciences—what I call transformational science" intended to push the cost-effectiveness of renewable energy.

These projects, along with the commercialization projects funded through the Solar America Initiative, are part of President George W. Bush's Advanced Energy Initiative. DOE plans to fund additional projects in fiscal year 2008.

The projects will address two priority technical areas: conversion of solar energy to electricity and conversion of solar energy to chemical fuels.

About $9.9 million and 14 projects involve research into converting sunlight to electricity. The goal is to greatly reduce costs while improving the conversion efficiency.

About $12.8 million for 13 projects involve research into direct conversion of sunlight into chemical fuels. This project overcomes a problem of the day vs. night variation of the solar resource and provides solar-derived energy in forms useful for transportation, residential, and industrial applications.

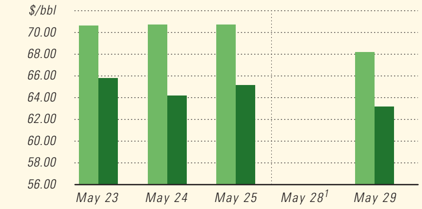
Wind power costs, investment up next 5 years

Global offshore wind power projects are projected to receive $11.8 billion of capital expenditure to finance new capacity to be installed in the next 5 years, a Douglas-Westwood Ltd. study said.

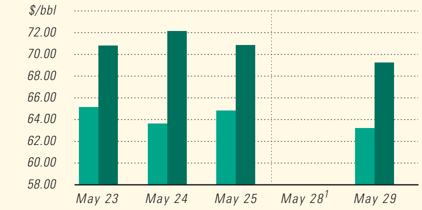
With just over 900 Mw of capacity installed currently, Douglas-Westwood expects an additional 3.6 Gw of new capacity to be

Industry Scoreboard

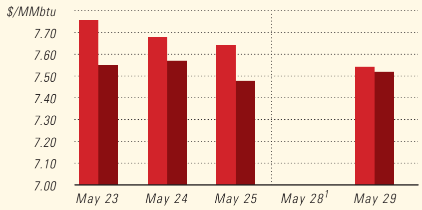
IPE BRENT / NYMEX LIGHT SWEET CRUDE



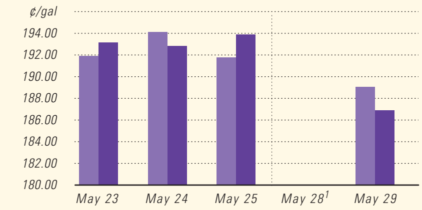
WTI CUSHING / BRENT SPOT



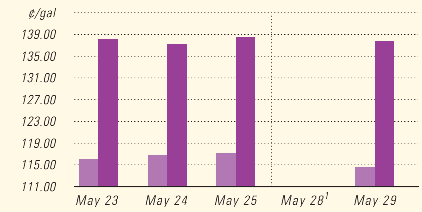
NYMEX NATURAL GAS / SPOT GAS - HENRY HUB



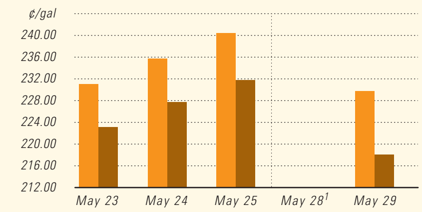
IPE GAS OIL / NYMEX HEATING OIL



PROPANE - MT. BELVIEU / BUTANE - MT. BELVIEU



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



[1]Not available
[2]Reformulated gasoline blendstock for oxygen blending

SCOREBOARD

Due to the holiday in the US, data for this week's industry Scoreboard are not available.

added during that period.

Capital expenditures on offshore wind power are expected to reach $3.8 billion/year by 2011, Douglas-Westwood director Andrew Reid told delegates at an Aberdeen conference May 24.

Northwestern Europe is the key spending area over the period, with the emergence of wind power markets off the US and China following. The UK is expected to become the largest offshore wind power market, with 1,645 Mw of new capacity forecast for the 5-year period. In Germany, 536 Mw of new capacity is expected to be installed during that time.

Costs for offshore wind development and construction are rising compared with the previous 5 years, and anticipated supply chain constraints are expected to continue pushing costs upward, Reid said. ✦

Exploration & Development — Quick Takes

BP signs $900 million Libyan exploration deal

BP PLC and a Libyan partner will drill 17 exploratory wells under a $900 million contract with Libya's National Oil Co. (NOC) covering 54,000 sq km in the onshore Ghadames basin and frontier offshore part of the Sirte basin. BP said its program will primarily target gas.

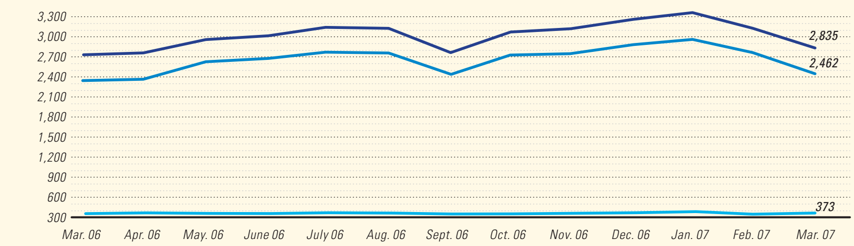
BP and the partner, Libya Investment Co., will shoot 5,500 km of 2D seismic survey and 30,000 sq km of 3D seismic survey.

"Successful exploration could lead to the drilling of around 20 appraisal wells," BP said.

BP Chief Executive Tony Hayward described the deal as the company's "single biggest exploration commitment." The company hasn't worked in Libya since the country nationalized the oil industry more than 30 years ago.

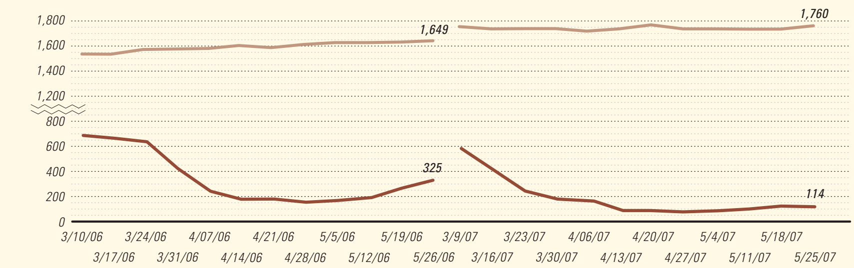
NOC wants to boost Libya's oil reserves to 20 billion boe under a plan covering 2005-15 through an aggressive offshore and frontier exploration program. NOC

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

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

"These targets will be met through existing NOC and joint venture operations and through investment by international oil companies expected to total some $7 billion," BP said.

Libyan professionals will receive petroleum education and training under a $50 million program organized by BP and NOC during the exploration and appraisal period of the new contract. If oil is found, an additional $50 million will be invested on training once production starts.

Total makes two oil finds on Angola's Block 32

Total E&P Angola (Block 32) Ltd. and its partners have made two more oil discoveries on deepwater Block 32 off Angola.

The Cominhos-1 well was drilled on the northeastern part of the block in 1,594 m of water and tested 6,258 b/d of 32° gravity oil. Oil came from a selected Lower Oligocene reservoir. The exploration well is 18 km north of the company's Caril-1 discovery (OGJ Online, Feb. 8, 2007).

The second well, Louro-1, was drilled in the southern part of Block 32 in 1,806 m of water and found both Miocene and Oligocene oil-bearing reservoirs. The find lies 4.5 km west of the Salsa-1 discovery.

Angola's Sonangol is concessionaire of Block 32. Total holds a 30% interest in the block and serves as operator. Other Block 32 partners are Marathon Oil Co. 30%, Sonangol EP 20%, Esso E&P Angola (Overseas) Ltd. 15%, and Petrogal 5%.

BP makes another strike on Angola's Block 31

BP Exploration (Angola) Ltd. and Angola's Sonangol EP have made their fourteenth oil discovery on ultradeepwater Block 31 off Angola.

The Cordelia well tested 2,063 b/d of oil through a $^{20}/_{64}$-in. choke. The well was drilled in 2,308 m of water using the Jack Ryan drillship and reached 4,040 m TVD.

The well is 3½ km southeast of the recent Miranda discovery, which flowed on test at 3,822 b/d through a $^{48}/_{64}$-in. choke (OGJ Online, May 7, 2007).

BP is the block operator and holds 26.67% interest. Other stakeholders are Esso E&P Angola (Block 31) Ltd. 25%, Sonangol 20%, Statoil Angola AS 13.33%, Marathon International Petroleum Angola Block 31 Ltd. 10%, and Total Group subsidiary Tepa (Block 31) Ltd. 5%.

MMS proposes Central Gulf Lease Sale 205

The US Minerals Management Service proposed an Oct. 3 lease sale in the newly configured Central Gulf of Mexico Planning Area.

The sale, to be held in New Orleans, would be the first central gulf sale in the MMS 2007-12 Outer Continental Shelf oil and gas leasing program.

The sale would involve 5,000 blocks covering more than 28.5 million acres. The acreage is 3-210 miles offshore in 4-3,400 m of water.

Sale 205 excludes the areas under moratorium and respects the buffers created for the Florida coast.

MMS estimates that as much as 1.3 billion bbl of oil and 5.2 tcf of natural gas could be discovered and produced from the lease sale area.

Statoil discovers light oil in Norwegian North Sea

Statoil ASA has found light oil in wildcat well 15/6-9 S, which was drilled on production license 303 in the Norwegian North Sea.

The well is 7 km north of Sleipner field and 3 km east of the 15/5-1 Dagny discovery in the central part of the North Sea. Seadrill's West Epsilon jack up drilled the well to 3,850 m TD in 114 m of water. West Epsilon will now drill a sidetrack to delineate the discovery.

Statoil said the find will contribute to its goal of producing 1 million boe/d from the Norwegian continental shelf until 2015.

Statoil has not carried out a production test and has focused on gathering extensive data collection and sampling. It will consider producing the discovery with a tie-in to Sleipner, Volve, or Gudrun.

Ascent Resources suspends Hungarian well

Ascent Resources PLC has suspended its PEN-102 exploration well in northeast Hungary as it investigates drilling a sidetrack well to target the Miocene gas reservoir.

Ascent drilled the PEN-102 well to 1,500 m TD within its Nyirseg exploration permits.

"Drilling and logging results indicated that the well had intercepted a fault system and consequently the target Miocene tuffaceous formations were encountered 38 m deeper than prognosis," Ascent said.

The company found residual gas in the deeper section of the reservoir and shot a seismic survey to identify the orientation of the fault system. After interpreting the survey, Ascent plans to drill a sidetrack well.

PEN-102 is the third well of a four-well program to be drilled under a farm-in agreement Ascent has with Canada's DualEx and Sweden's Petro Pequnia. The partners will acquire working interests in the Nyirseg permits of 37.5% and 2%, respectively, by paying 75% and 4% of the costs of these wells. Through its subsidiary PetroHungaria, Ascent will contribute the outstanding 21% for the drilling costs and keep a 60.5% working interest in the permits.

"The drilling rig will move to the last of the four farm-in wells, VAM-1, a gas exploration well designed to test exploration prospects in both the Miocene and Pannonian formations in the Vamospercs area, some 14 km farther southwest of PEN-102," Ascent said.

Ascent said, "A successful sidetrack of the PEN-102 could yet add reserves to the planned Peneszlek development in Hungary," which includes the PEN-104 discovery and other proved reserves in PEN-9 and PEN-12. ✦

Drilling & Production — *Quick Takes*

Gas sales start from Turkish Black Sea

The first natural gas sold from the Turkish Black Sea has begun flowing from the South Akcakoca subbasin to AKSA, a Turkish gas distributor, reports Toreador Resources Corp. (OGJ, Apr. 16, 2007, Newsletter).

Initial production for the AKSA sale is 29 MMcfd of gas from three wells on the Akkaya platform. Production is expected to increase to 50 MMcfd by this year's third quarter, when three platforms are on stream. The contract is for 3 years, based on volume.

Toreador has 36.75% interest in the project, state-owned TPAO has 51%, and Stratic Energy Corp. has 12.25%.

Pearl starts up Jasmine C platform off Thailand

Pearl Energy Ltd., a unit of Aabar Petroleum Investments Co. PJSC of Abu Dhabi, began production of 1,450 b/d of oil from a single development well at the Jasmine C platform in the Gulf of Thailand.

The platform is connected via a 3.8-km pipeline to the Jasmine venture MV7 floating production, storage, and offloading vessel. Its 1,150-tonne processing topsides were installed Mar. 21, and drilling of the first group of development wells started Apr. 25. Two additional development wells, C2 and C3, will be completed and brought on production in the next few days of the initial phase of this drilling program, which will comprise a total of 12 development wells and 3 water disposal wells.

In addition, engineering design is under way on two additional platforms, which are to be installed in and around the Jasmine production area following a successful exploration program conducted in first half 2006.

At the end of this year's first quarter, two existing platforms, Jasmine A and B, were producing at a gross average rate of 24,000 b/d of oil. Production started at the Jasmine A platform June 7, 2005, and at Jasmine B on Jan. 22 of this year (OGJ Online, Jan. 26, 2007).

Venoco runs six rigs in Sacramento basin

Venoco Inc., Denver, spud 34 wells in the quarter ended Mar. 31 in the Sacramento basin, where it plans to drill more than 120 wells in 2007.

Venoco doubled the number of rigs it is running in the basin to six from three in the quarter.

The company's program is focused mainly on infill drilling and recompletions, and it set casing on 30 of the 34 first quarter wells. More completion rigs are expected to be available the rest of the year.

The company has expanded its land position 164,000 net acres in the basin, where it operates about 250 gas wells. ✦

Processing — *Quick Takes*

Koch to add hydrocracking unit at Navajo refinery

Koch Partners LP will design, supply, and install a gas oil mild hydrocracker at Navajo Refining Co. LP's 60,000 b/cd refinery in Artesia, NM.

The unit, which will use Process Dynamics Inc.'s IsoTherming process, will have an initial capacity of 15,000 b/sd and be expandable to 30,000 b/sd. It is expected to be operational in fourth quarter 2008.

The project will increase the refinery's capacity to process outside feedstocks and increase yields of higher-valued products. It also will be a key component in the company's overall strategy for producing low-sulfur transportation fuels.

Combine lets coker contract for Jubail refinery

Aramco Services Co. and Total France have let a contract to Foster Wheeler USA Corp. for a process design package for a new delayed coker, which will be part of the 400,000 b/d export refinery to be built in Jubail Industrial City, Saudi Arabia.

The coker design package will be developed by Foster Wheeler's Houston office. Terms of the award were not disclosed.

The delayed coker, expected to be one of the largest in the world, will be based on Foster Wheeler's selective yield delayed coking process, which upgrades heavy, high-sulfur residue feed into high value transport fuels with minimum fuel coke yields.

The planned Jubail refinery will be a grassroots full-conversion plant designed to process Arabian heavy crude. It is slated for startup in 2011 (OGJ Online, Sept. 4, 2006).

Nigerian group wins Port Harcourt refinery bid

Blue Star, a consortium of Nigerian companies Zenon Oil, Dangote Oil, and Gas & Transnational Corp., paid $561 million to acquire 51% of a government-owned stake in Nigeria's Port Harcourt refinery.

The companies, which are headed by close associates of the country's outgoing President Olusegun Obasanjo, won the bid over UK-based international steel baron Lakshmi Niwas Mittal, who bid $550 million.

Blue Star emerged the winner in open bidding conducted last weekend in Abuja by the Nigerian privatization agency Bureau of Public Enterprises.

Sources at Indian government-owned refiner Hindustan Petroleum Corp. Ltd. (HPCL) said Mittal originally had planned to bid for the 210,000 b/d refinery with HPCL, but instead bid it alone when HPCL decided against investing in the facility.

The Indian-born Mittal earlier this year had accepted a 49% stake in HPCL's proposed $3.3 billion Bhatinda refinery to be built in Punjab, northwestern India (OGJ Online, Feb. 22, 2007).

India's largest refiner Indian Oil Corp., also invited to bid on the Port Harcourt refinery, decided against making an offer. Two other bidders, local fuel marketer Oando and a combine of Sahara and Refinee PetroPlus, were disqualified. ✦

Transportation — *Quick Takes*

Contract let for west-east Malaysian oil line

Ranhill Engineers & Constructors Sdn. Bhd. (REC), a wholly owned unit of Ranhill Bhd. of Kuala Lumpur, has secured a contract for the design, engineering, procurement, construction, and testing of a 320-km west-east oil pipeline across Malaysia.

REC entered into a master alliance agreement with Trans-Peninsula Petroleum Sdn. Bhd. (Transpen), also of Kuala Lumpur, and Tripatra Engineers & Consultants of Jakarta for the Malaysian Trans-Peninsula Pipeline.

Ranhill said Transpen was granted exclusive rights by the Malaysian government to develop the project, which will receive oil from carriers off Western Peninsular Malaysia and store, transport, and deliver oil to carriers off Eastern Peninsular Malaysia.

Work on the pipeline is slated to start in 2008 and be completed in 2014, according to Transpen Chairman Rahim Kamil Sulaiman, who told a news conference that oil would be loaded onto tankers bound for Japan, China, and South Korea, bypassing Singapore and the Malacca Strait, which currently supports transportation of about 50% of the world's oil.

Sulaiman's statement confirmed reports in early May that Malaysia had agreed to build the pipeline from northwestern Kedah state, across Perak state, to northeastern Kelantan state which fronts the South China Sea. At the time Prime Minister Datuk Seri Abdullah Ahmad Badawi said the project would enable Middle Eastern shippers to reach East Asian markets without risking cargoes along the busy, pirate-prone Malacca Strait (OGJ Online, May 7, 2007).

The Ranhill statement did not mention refineries. However, Mahdzir Khalid, the chief minister for Kedah state, through which the line will extend, told reporters that two refineries with a combined refining capacity of 450,000 b/d will be built in Kedah by 2010. He said Malaysia's SKS Ventures and Merapoh Resources Corp. would reveal arrangements for the refineries in August.

FERC issues final EIS for Gulf South gas line

The US Federal Energy Regulatory Commission concluded that the proposed East Texas-to-Mississippi natural gas pipeline project is environmentally acceptable, FERC said in a final environmental impact statement.

The project, proposed by Gulf South Pipeline Co., would transport 1.7 bcfd of gas from East Texas to the US Gulf Coast, Midwest, Northeast, and Southeast.

The final EIS follows a preliminary statement issued Feb. 9. FERC said commissioners will consider the final EIS and other staff recommendations before issuing a decision on the project.

Equatorial Guinea LNG train delivers early

Marathon Oil Corp. and its partners in Equatorial Guinea LNG Co. Ltd. have shipped their first cargo 6 months ahead of the original schedule.

The cargo was shipped from Train 1 on Bioko Island after the $1.5 billion project was completed within budget.

BG Gas Marketing Ltd. owns the cargo under a 17-year agreement calling for the plant's full capacity of 3.4 million tonnes/year.

The first cargo was destined for Lake Charles, La., although BG has the option to divert the cargo elsewhere.

Interest holders in the plant are Marathon 60%, state-owned Sonagas 25%, Marubeni Gas Development Co. Ltd. 6.5%, and Mitsui & Co. Ltd. 8.5%.

Northeast Gateway LNG port gets Marad nod

Excelerate Energy LLC subsidiary Northeast Gateway Energy Bridge LLC has received its deepwater port license from the US Maritime Administration (Marad) for its Northeast Gateway deepwater LNG importation facility in Massachusetts Bay.

Construction will begin soon, and gas deliveries from the Northeast Gateway facility to Massachusetts and the rest of New England are anticipated by yearend.

The LNG facility will be designed to handle peak deliveries of as much as 800 MMcfd of gas. During normal operations the facility will be able to deliver about 500 MMcfd of gas, or 20% of New England's current annual gas consumption.

The port's infrastructure will feature two submerged turret loading buoys supplied by Advanced Production & Loading Inc.

Excelerate Energy will build and own the Northeast Gateway deepwater port 18 miles east of Boston. It will be operated by Skaugen Offshore and will accommodate Excelerate's proprietary Energy Bridge Regasification Vessel (EBRV) fleet operated by Exmar NV.

Spectra Energy, formerly Duke Energy, will build a 16-mile subsea pipeline from its existing HubLine to the deepwater port site to transfer gas from the vessels into New England's gas pipeline network.

Northeast Gateway will be the first new LNG importation facility to serve the east coast in more than 25 years. And it is the world's second deepwater LNG importation facility.

The first, Gulf Gateway, 116 miles south of Cameron Parish, La., in the Gulf of Mexico, is owned and operated also by Excelerate Energy, which recently increased its LNG vessel fleet through equity investments in three new EBRVs to be constructed by 2010. This brings the company's LNG vessel involvement to eight regasification vessels and one traditional LNG carrier.

California rejects Cabrillo Port LNG project

California Gov. Arnold Schwarzenegger has rejected BHP Billiton Ltd.'s proposed $800 million Cabrillo Port LNG project that was to be built 14 miles off Ventura County.

Australia's BHP had no immediate comment regarding what additional steps it might take regarding Cabrillo Port.

In April both the California Coastal Commission and the California State Lands Commission voted against the proposal. The US West Coast has no LNG ports.

Sempra Energy unit Sempra LNG is proceeding with plans for its Energía Costa Azul LNG receiving terminal in Baja California, Mexico. Natural gas could be transported from it into California. That plant is slated for operation in 2008. ✦

Calendar

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

OIL&GAS JOURNAL online research center.

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

2007

JUNE

Society of Petrophysicists and Well Log Analysts (SPWLA) Annual Symposium, Austin, (713) 947-8727, (713) 947-7181 (fax), e-mail: info@spwla.org, website: www.spwla.org. 3-6.

International Caspian Oil & Gas Exhibition & Conference, Baku, +44 (0) 207 596 5233, +44 (0) 207 596 5106 (fax), e-mail: julia.romanenko@ite-exhibitions.com, website: www.caspianoil-gas.co.uk. 5-8.

International Liquefied Petroleum Gas Congress & Exhibition, Nice, 32 2 566 91 20 32 2 566 91 29 (fax), website: www.aegpl.com. 6-8.

Society of Petroleum Evaluation Engineers Annual Meeting, Vail, Colo., (713) 651-1639, e-mail: bkspee@aol.com, website: www.spee.org. 9-12.

PIRA Scenario Planning Conference, London, 212-686-6808, 212-686-6628 (fax), e-mail: sales@pira.com, website: www.pira.com. 11.

Asian Petrochemicals & Gas Technology Conference & Exhibition, Kuala Lumpur, +44 (0) 20 7357 8394, e-mail: Conference@EuroPetro.com, website: www.europetro.com. 11-12.

Central European Gas Conference, Berlin, +44 (0)20 8275 5198, +44 (0)20 8275 5401 (fax), e-mail: CEGC@lynne-evens.com, website: www.thecegc.com. 11-13.

ERTC Refining Management and Strategy Conference, Vienna, 44 1737 365100, +44 1737 365101 (fax), e-mail: events@gtforum.com, website: www.gtforum.com. 11-13.

ILTA Annual International Operating Conference & Trade Show, Houston, (202) 842-9200, (202) 326-8660 (fax), e-mail: info@ilta.org, website: www.ilta.org. 11-13.

IPAA Midyear Meeting, Henderson, Nev., (202) 857-4722, (202) 857-4799 (fax), website: www.ipaa.org/meetings. 11-13.

EAGE/SPE Europec Conference and Exhibition, London, +31 30 6354055, +31 30 6343524 (fax), e-mail: eage@eage.org, website: www.eage.org. 11-14.

PIRA London Energy Conference, London, 212-686-6808, 212-686-6628 (fax), e-mail: sales@pira.com, website: www.pira.com. 12.

Health and Safety Excellence Conference, Barcelona, +420 257 218 505, +420 257 218 508 (fax), e-mail: healthandsafety@jacobfleming.com, website: www.jacobfleming.com. 12-13.

GO-EXPO Gas and Oil Exposition, Calgary, Alta.,

(403) 209-3555, (403) 245-8649 (fax), website: www.petroleumshow.com. 12-14.

Asian Downstream Technology & Catalyst Conference & Exhibition, Kuala Lumpur, +44 (0) 20 7357 8394, e-mail: Conference@EuroPetro.com, website: www.europetro.com. 13-14.

IADC World Drilling Conference, Paris, (713) 292-1945, (713) 292-1946 (fax); e-mail: info@iadc.org, website: www.iadc.org. 13-14.

PIRA Understanding Global Oil Markets Conference, London, 212-686-6808, 212-686-6628 (fax), e-mail: sales@pira.com, website: www.pira.com. 13-14.

Asian Oil, Gas & Petrochemical Engineering Exhibition, Kuala Lumpur, +60 3 4041 0311, +60 3 4043 7241 (fax), e-mail: oga@oesallworld.com, website: www.allworldexhibitions.com. 13-15.

GazChem Conference, Port of Spain, +44 20 7903 2444, +44 20 7903 2432 (fax), e-mail: conferences@crugroup.com, website: www.britishsulphurevents.com/Gazchem07_prog.htm. 17-20.

Newfoundland Ocean Industries Association Conference, St. John's, Newf., (709) 758-6610, (709) 758-6611 (fax), e-mail: noia@noianet.com, website: www.noianet.com. 18-22.

Offshore Newfoundland Petroleum Show, St. John's, Newf., (403) 209 3555, (403) 245-8649 (fax), website: www.petroleumshow.com. 19-20.

Brasil Offshore International Oil & Gas Trade Show & Conference, Macae, 55 11 3816 2227, 55 11 3816 2919 (fax), e-mail: contato@brasiloffshore.com, website: www.brasiloffshore.com. 19-22.

PIRA Scenario Planning Conference, Houston, 212-686-6808, 212-686-6628, e-mail: sales@pira.com. website: www.pira.com. 25.

Russia & CIS Refining & Petrochemicals Business Conference & Exhibition, Moscow, +44 (0) 20 7357 8394, e-mail: Conferences@EuroPetro.com, website: www.europetro.com. 25-26.

API Exploration and Production Standards Conference on Oilfield Equipment and Materials, San Francisco, (202) 682-8000, (202) 682-8222 (fax), website: www.api.org. 25-29.

PIRA Understanding Global Oil Markets Conference, Houston, 212-686-6808, 212-686-6628 (fax), e-mail: sales@pira.com. website: www.pira.com. 26-27.

CERA East Meets West Executive Conference, Istanbul, (800) 597-4793, (617) 866-5992 (fax), e-mail: register@cera.com, website: www.cera.com. 26-28.

Power-Gen Europe Conference, Madrid, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.pennwell.com. 26-28.

Russian Petroleum Congress, Moscow, +44 (0) 207 596 5233, +44 (0) 207 596 5106 (fax), e-mail: oilgas@ite-exhibitions.com, website: www.ite-exhibitions.com. 26-28.

Moscow International Oil & Gas Conference & Exhibition, Moscow, +44 (0) 207 596 5233, +44 (0) 207 596 5106 (fax), e-mail: oilgas@ite-exhibitions.com, website: www.ite-exhibitions.com/og. 26-29.

JULY

IPAA OGIS, London, (202) 857-4722, (202) 857-4799 (fax), website: www.ipaa.org/meetings. 11.

Calendar

Carbon Sequestration Development & Finance Summit, Houston, (818) 888-4444, website: www.infocastinc.com/sequest07.html. 11-13.

Oil Sands and Heavy Oil Technologies Conference & Exhibition, Calgary, Alta., (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.pennwellpetroleumgroup.com. 18-20.

Purvin & Gertz Annual Asia LPG Seminar, Singapore, (713) 236-0318, (713) 236-8490 (fax), e-mail: glrodriguez@purvingertz.com, website: www.purvingertz.com. 25-28.

West China International Oil & Gas Conference, Urumqi, Xinjiang, +44 (0) 207 596 5233, +44 (0) 207 596 5106 (fax), e-mail: oilgas@ite-exhibitions.com, website: www.ite-exhibitions.com. 26-27.

International Petroleum & Petrochemical Exhibition, , Urumqi, Xinjiang, +44 (0) 207 596 5233, +44 (0) 207 596 5106 (fax), e-mail: oilgas@ite-exhibitions.com, website: www.ite-exhibitions.com. 26-28.

AUGUST

Coal-Gen Conference, Milwaukee, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.pennwell.com. 1-3.

Rocky Mountain Natural Gas Strategy Conference & Investment Form, Denver, (303) 861-0362, (303) 861-0373 (fax), e-mail: cogaconference@aol.com, website: www.coga.org. 13-15.

American Chemical Society National Meeting & Exposition, Boston, (202) 872-4600, (202) 872-4615 (fax), e-mail: natlmtgs@acs.org, website: www.acs.org. 19-23.

NAPE Summer Expo, Houston, (817) 847-7700, (817) 847-7703 (fax), e-mail: nape@landman.org, website: www.napeonline.com. 23-24.

IADC Well Control of the Americas Conference & Exhibition, Galveston, Tex., (713) 292-1945, (713) 292-1946 (fax); e-mail: info@iadc.org, website: www.iadc.org. 28-29.

SEPTEMBER

Brasil Subsea Conference & Exhibition, Rio de Janeiro, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.pennwellpetroleumgroup.com. 1.

SPE/EAGE Reservoir Characterization and Simulation Conference, Muscat, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 3-5.

Power-Gen Asia Conference, Bangkok, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.pennwell.com. 4-6.

Offshore Europe Oil & Gas Conference and Exhibition, Aberdeen, +44 (0) 208 439 8890, +44 (0) 208 439 8897 (fax), e-mail: oe2007@spearhead.co.uk, website: www.offshore-europe.co.uk. 4-7.

Black Sea Oil & Gas Summit, Istanbul, +90 312 454 00 00-1412, +90 312 454 00 01, e-mail: bsogs2007@flaptour.com.tr, website: www.bsogs2007.org. 5-6.

Corrosion Solutions Conference, Sunriver, Ore., (541) 926-4211, ext. 6280, website: www.corrosionconference.com. 9-13.

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

SPE Asia Pacific Health Safety Security Environment Conference, Bangkok, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 10-12.

Turbomachinery Symposium, Houston, (979) 845-7417 (979) 845-1835 (fax), e-mail: turbo@turbo-lab.tamu.edu, website: http://turbolab.tamu.edu. 10-13.

Oil Sands Trade Show & Conference, Fort McMurray, Alta., (403) 209-3555, (403) 245-8649 (fax), website: www.petroleumshow.com. 11-12.

AAPG Annual Eastern Meeting, Lexington, (859) 257-5500, ext. 173, website: www.esaapg07.org. 16-18.

United States Association for Energy Economics/IAEE North American Conference, Houston, (216) 464-2785, (216) 464-2768 (fax), website: www.usaee.org. 16-19.

Russia & CIS Petrochemicals & Gas Technology Conference & Exhibition, Moscow, +44 (0) 20 7357 8394, e-mail: Conference@EuroPetro.com, website: www.europetro.com. 17-18.

API Fall Refining and Equipment Standards Meeting, San Antonio, (202) 682-8000, (202) 682-8222 (fax), website: www.api.org. 17-19.

Russia & CIS Refining Technology Conference & Exhibition, Moscow, +44 (0) 20 7357 8394, e-mail: Conference@EuroPetro.com, website: www.europetro.com. 19-20.

IOGCC Annual Meeting, New Orleans, (405) 525-3556, (405) 525-3592 (fax), e-mail: iogcc@iogcc.state.ok.us, website: www.iogcc.state.ok.us. 23-25.

Society of Exploration Geophysicists (SEG) Annual Meeting, San Antonio, (918) 497-5500, (918) 497-5557 (fax), e-mail: web@seg.org, website: www.seg.org. 23-28.

Russia & CIS Petrochemicals Technology Conference & Exhibition, Moscow, +44 (0) 20 7357 8394, e-mail: Conferences@EuroPetro.com, website: www.europetro.com. 25-26.

Annual Engineering & Construction Contracting Association Conference, Colorado Springs, Colo., (877) 484-3322, (713) 877-8130 (fax), e-mail: registration@ecc-association.org, website: www.ecc-association.org. 27-28.

Russia & CIS Refining Technology Conference & Exhibition, Moscow, +44 (0) 20 7357 8394, e-mail: Conferences@EuroPetro.com, website: www.europetro.com. 27-28.

OCTOBER

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Oil Shale Symposium, Golden, Colo., (303) 384-2235, e-mail: jboak@mines.edu, website: www.mines.edu/outreach/cont_ed/oilshale. 15-19.

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

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

PIRA New York Annual Conference, New York, 212-

Calendar

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

IPAA Annual Meeting, New Orleans, (202) 857-4722, (202) 857-4799 (fax), website: www.ipaa.org/meetings. 22-24.

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

Kuwait International Oil & Gas Exhibition, Kuwait City, +32 2 474 8264, +32 2 474 8397 (fax), e-mail: david@kuioge.com, website: www.kioge.org. 22-25.

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

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

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

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

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

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

NOVEMBER

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

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

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

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

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

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

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

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

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

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

DECEMBER

International Oil and Gas Industry Exhibition & Conference, Suntec, +44 (0)20 7840 2100, +44

(0)20 7840 2111 (fax), e-mail: osea@oesallworld.com, website: www.allworldexhibitions.com. 2-5.

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

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

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

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

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

PIRA Understanding Global Oil Markets Conference, New York, 212-686-6808, 212-686-6628 (fax), e-mail: sales@pira.com, website: www.pira.com10-11.

2008

JANUARY

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

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

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

MARCH

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

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

Offshore Asia Conference & Exhibition, Kuala Lumpur, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.offshoreasiaevent.com. 18-20.

Middle East Geosciences Conference and Exhibition, Bahrain, +60 3 4041 0311, +60 3 4043 7241 (fax), e-mail: geo@oesallworld.com, website: www.allworldexhibitions.com/oil. 24-26.

MAY

IOGCC Midyear Meeting, Calgary, Alta., (405) 525-3556, (405) 525-3592 (fax), e-mail: iogcc@iogcc.state.ok.us, website: www.iogcc.state.ok.us. 2-5.

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

JUNE

World Petroleum Congress, Madrid, +34 91 745 3008, +34 91 563 8496 (fax), e-mail: info@19wpc.com, website: www.19wpc.com. June 29- July 3.

AUGUST

Offshore Northern Sea Exhibition & Conference, Stavanger, +47 51 59 81 00, +47 51 55 10 15 (fax), e-mail: info@ons.no, website: www.ons.no. 26-29.

R&D: results amid doubt

Angel White
Associate Editor

Recent actions by the administration of US President George W. Bush raise industry concerns about the future of federal funding for oil and gas research and development. The administration has repeatedly excluded from its annual budget proposals funding for oil and gas R&D by the Department of Energy's Office of Fossil Energy (OFE). Yet OFE continues to participate in such projects, although at decreased funding levels.

In fact, OFE's National Energy Technology Laboratory and Texas A&M University recently completed a 3-year, $890,000 research project that developed a computerized method for rapidly interpreting field tracer tests. OFE funded $630,000 of the project's cost, and the university provided the rest.

OFE, A&M project

The new method integrates computer simulations with history-matching techniques, allowing scientists to design tracer tests and use PC-based software to interpret the data. This process, DOE said, is much faster than conventional history-matching.

DOE explained that the new software uses "generalized travel time inversion" technology to adapt sophisticated computer modeling to the personal computer. The cost and time savings, coupled with the streamlined model and accessible PC-based tools, make the technology feasible for small independent producers.

The system enhances reservoir characterization, enabling its users to identify unswept regions in mature fields with high oil or gas saturation. It uses computer models to characterize a productive oil reservoir. History-matching then calibrates the model by correlating its predictions of oil and gas production to a reservoir's actual production history.

A key input to history-matching is data from tracer tests, in which traceable gases or liquids are injected into a well to determine the paths and velocities of fluids as they move through the reservoir. This information helps reservoir engineers calculate how much oil remains in the reservoir and determine the most efficient way to sweep the residual oil from the reservoir.

Application

The new computer-modeling tool promises to quickly and economically estimate the amounts of oil remaining in reservoir compartments of mature fields and thus to improve planning for its recovery.

According to DOE, more than two thirds of all the oil discovered in the US remains in place in the subsurface and is economically unrecoverable with current technology. About 218 billion bbl of this oil, categorized as bypassed oil, lies at depths of less than 5,000 ft.

Bypassed oil represents a huge target for the roughly 7,000 independent producers active in thousands of mature US fields, and it could account for a large share of the country's oil supply, DOE said in a statement on its web site.

DOE added that much bypassed oil lies in difficult-to-access pockets and that predicting the location and size of these elusive, compartmentalized deposits is costly because it often requires complex computing.

Many independent producers, the agency said, aren't able to commit the labor or buy the expensive supercomputer time required to create and operate the models needed to access bypassed oil.

With federal R&D funding uncertain, Texas A&M researchers have responded to interest in their new technology by assembling an industry R&D consortium funded by eight production and service companies. The consortium has won a grant from the National Science Foundation, and its technology has been adopted by two companies.

Future funding

Federal funding of oil and gas R&D projects has been addressed by several industry organizations, including the Independent Petroleum Association of America and Independent Petroleum Association of Mountain States (OGJ, Mar. 19, 2007, p. 30; OGJ Online, Apr. 13, 2007).

In the past, Congress has passed budgets that included such funding even when the Bush administration didn't request it. In fiscal 2006, however, it funded the government with continuing resolutions without passing a budget, leaving oil and gas R&D at 2005 funding levels. The practice of funding government with continuing resolutions has continued in the current fiscal year so Congress can concentrate on the budget for 2008.

Funding for OFE's R&D programs, however, remains in doubt because the entire DOE budget is under review. ✦

Editorial

From fallacy to law

Fallacy plus propaganda can equal irresistible politics and expensive mistakes. In a tantrum over gasoline prices, the US House has passed a bill that makes "price-gouging" a federal crime. The Senate will consider similar legislation this month. The measure is an exquisite fallacy enshrouded in propaganda. Unless lawmakers come to their senses, it will pass.

The bill, HR 1252, makes a crime out of behavior it can't define. During an emergency declared by the US president, it would be illegal for anyone to sell oil products at a price that was "unconscionably excessive" and that indicated the seller was "taking unfair advantage of the circumstances related to an energy emergency to increase prices unreasonably." The bill offers parameters by which to assess these ambiguities, among them whether a price "grossly exceeds" either the average price during the 30 days before the emergency or the prices of products available from other sellers in the same area. Sellers must await prosecution to learn the meaning of "grossly exceeds."

Riot of adverbs

From nowhere amid this riot of scornful adverbs does there emerge a useful definition of the activity that Congress would make a criminal offense. Indeed, no such definition is possible because the activity never occurs in any general way. Competition doesn't allow it. Sellers who aggressively raise prices during emergency shortages lose business to competitors who do not. Markets are self-enforcing. Continuous monitoring by federal authorities ensures that fuel markets work. This is partly why all formal investigations of past price increases have uncovered no "gouging" by refiners or major marketers.

HR 1252 thus makes a federal crime out of behavior that its sponsors can't define, that economic theory rejects, and that history says doesn't exist. It's a meaningless stack of empty phrases—"price-gouging," "unconscionably excessive," "unfair advantage," "grossly exceeds." It's propaganda devoid of substance that threatens victims of unlucky interpretation with stiff civil and criminal fines, even jail terms. Lawmaking can't get much worse than this.

Yet who will oppose a measure that professes to capture and punish "price-gougers?" Americans spoiled by decades of low fuel prices have ridden their excesses into an uncomfortable market turn. Many of them are angry and want the government to make prices low again. Lawmakers are accommodating them by inventing a class of villains. They'll be hard to dissuade from their mistake.

And what a mistake it will prove to be the next time hurricanes wallop refineries or something chokes crude oil supplies. Prices jump at times like those. So what is an oil seller who doesn't want to go to prison supposed to do? Allowing prices to rise with the market risks having the increase deemed "grossly excessive." The safe alternative is to sell below the market, drain inventories, shun replacement supplies, and suspend sales until the emergency subsides.

HR 1252 thus would discourage product sales in a supply emergency, just what consumers don't need. The gullible would see compensation in the absence of "price-gouging." But there's no price-gouging now. Why impose a costly and unnecessary tradeoff?

Self-destructive nonsense like HR 1252 comes about because of an unseemly need of politicians to assign blame. When gasoline prices arouse public ire, politicians blame oil companies. They do so despite the investigations that regularly find oil companies innocent of price manipulation. And they incite suspicions about "price-gouging" when no such thing exists in a free market.

Dodging blame

This all is a dodge. Blame for the elevation of fuel prices belongs to Congress and federal agencies. Fuel specifications are stricter and more prescriptive than they need to be and add unnecessary costs to the manufacture of gasoline, diesel, and other oil products. US laws and regulations, on matters ranging from federal oil and gas leasing to permitting of refineries and pipelines, have for decades militated against the expansion of supply. With consumption unrestrained, a price-raising crunch was inevitable.

Instead of accepting blame and correcting errors, though, lawmakers seem determined to spin law out of fallacy and claim, incredibly, to be helping consumers. They might just as well outlaw hurricanes. ✦

Downstream mergers, capacity hikes persist

William L. Leffler
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Houston

Since 1995, a totally unanticipated restructuring of the US refining industry has reconstituted the corporate identities of the largest refiners. By 2007, venerable names—Amoco, Arco, Ashland, Clark, Coastal, Diamond-Shamrock, Texaco, and Unocal—had disappeared from the roster. Has the industry reached such concentration levels that further mergers and acquisitions will be successfully challenged by government agencies? Is the M&A party over? This article concludes that it is not.

According to the 1995 OGJ refinery survey, 91 companies operated 169 refineries with 15.4 million b/d of refining capacity in the US (OGJ, Dec. 18, 1995, p. 41). By 2007, OGJ reported, the number of refining companies had dropped to 51 companies operating 131 refineries with a total capacity of 17.3 million b/cd (OGJ, Dec. 18, 2006, p. 56, and OGJ Online survey).

In the intervening years, refinery capacity had risen by 1.9 million b/d. Fig. 1 shows the change in the structure over those years. The cumulative capacities for the individual companies are arrayed from the largest companies on the left to the smallest on the right. During 1995-2006 the curve moved up (more capacity) and to the left (fewer companies).

Remarkably, no new grassroots refineries were built during that period, but total US capacity increased by the equivalent of almost one world-class refinery (250,000 b/d) every year. Table 1, taken from OGJ refinery surveys, shows a recap of the largest refiners in 1995 and 2006 (those with more than 200,000 b/d of capacity.) In a rash of mergers and acquisitions, the top 25 refining companies in 1995 had been absorbed by the top 14 of 2006 in the manner shown in Fig. 2. In the process, there were survivors and casualties.

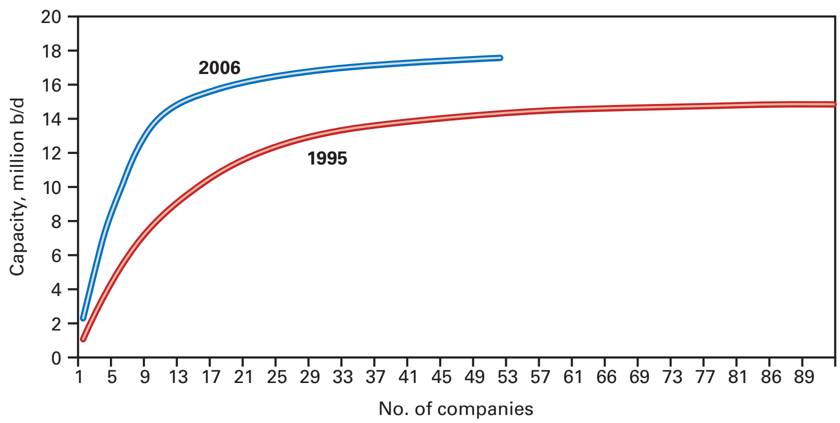
Survivors

Among the survivors were:

- Shell Oil Co., which absorbed Texaco's refining business and, with Saudi Aramco, Texaco's interest in the Star joint venture, which was renamed Motiva Enterprises.
- BP Oil Co., which took over Amoco and Arco.
- Sunoco (formerly Sun), which acquired part of Coastal Corp.
- Marathon Oil Corp., which absorbed Ashland Petroleum Co.
- Koch Industries Inc. and its subsidiary Flint Hills Resources.
- Saudi Aramco, joint venture owner of Motiva with Shell.
- Citgo Petroleum Corp., owned by Venezuelan national oil company Petroleos de Venezuela SA (PDVSA).
- Chevron Corp., which previously had absorbed Gulf Oil Corp. and later acquired Texaco Inc. and Unocal Corp. but received none of their refining assets.
- Also, in two "mergers of equals," Exxon Corp. and Mobil Corp. merged to become ExxonMobil Corp., and Conoco Inc.—a spin-off from DuPont Chemical Co.—merged with Phillips Petroleum Co. (which previously had absorbed Tosco Corp.) and became ConocoPhillips.

CUMULATIVE CAPACITIES* OF US REFINING COMPANIES

Fig. 1



*The cumulative capacities for the individual companies are arrayed from the largest companies on the left to the smallest on the right. In 2006, the curve has moved up (more capacity) and to the left (fewer companies).

• New entrants Valero Energy Corp. and Tesoro Corp., which didn't even appear on the 1995 list, between them swept up another 19 refineries during the 12 years from 1995 to 2007.

Casualties

Among the casualties:

• Amoco Oil Co. was absorbed by BP.

• Star Enterprises, the Shell-Texaco-Saudi Aramco joint venture, was absorbed by Shell and Saudi Aramco.

• Tosco Corp. was swallowed by Phillips before the Conoco-Phillips merger.

• Arco was acquired by BP.

• Texaco's refining assets were absorbed by Shell and Motiva.

• Ashland Petroleum Co. was taken over by Marathon.

• Clark Oil & Refining Corp., after a name change to Premcor Group Inc., was absorbed by Valero.

• Lyondell-Citgo Refining Co. was incorporated into Lyondell Chemical Corp.

• Phibro Refining Co. was acquired by Valero.

• Coastal Refining & Marketing Co. was absorbed in pieces by Sunoco and Valero.

• Fina Oil & Chemical Co. became part of Total SA.

• Mapco Petroleum Inc. was purchased by Delek US Holdings Inc.

• Diamond Shamrock Corp. merged with Ultramar Ltd. then was absorbed by Valero.

• Unocal Corp. was absorbed in part by PDVSA's Citgo and then by Tosco Corp., which ultimately became part of Phillips and then ConocoPhillips.

Questions surface

The disappearance of so many corporate entities during such a busy period of expansion might provoke some questions in suspicious minds. Stoking that interest might be the rise in the level of profitability in the refining sector from the unacceptable levels of the mid-1990s to the much more attractive levels and investment opportunities evident in the last 2 years.[1] Indeed, OGJ's Construction Survey at yearend 2006 told of another 600,000 b/d of US capacity under construction or planned, including two new refineries.

The top 14 companies' ownership of capacity, which increased to 86% in 2006 from 66% in 1995, might prompt the same wary minds to ask: "Is too much control in the hands of too few companies?"

Almost 100 years have passed since the US Supreme Court upheld a lower court's decision to break up the Standard Oil Co. into 34 independent companies and undid its monopolistic control of crude oil and oil product prices. Standard had used refinery ownership as its primary tool. Yet by 2007, direct descendents of Standard Oil figure prominently as the industry survivors (Table 1).

ExxonMobil, for example, is comprised of the former Exxon—derived from Esso, which was originally Standard Oil of New Jersey—and Mobil Oil, formerly Socony Vacuum, which was originally Standard Oil Co. of New York. In addition, Chevron is comprised of companies that were formerly Standard Oil of California and Soky, Standard Oil of Kentucky. ConocoPhillips descended originally from Continental Oil Co., and Marathon Oil Co. originally was Ohio Oil Co., both Standard Oil companies.

Other Standard Oil companies disappeared into BP—Sohio (Standard Oil of Ohio) and Arco (Atlantic Refining Co., later Atlantic Richfield). More than a score of other refineries originally built by Standard Oil and its successors are now owned by Valero, Flint Hills, ConocoPhillips, and Tesoro.

Largest US refining companies*

Table 1

1995	2006
Chevron USA Products Inc.	Valero Energy Corp.
Shell Oil Co.	ConocoPhillips
Amoco Oil Co.	ExxonMobil Corp.
Exxon Co. USA	BP Oil Co.
Mobil Oil Co.	Shell Oil Co.
BP Oil Co.	Marathon Oil Corp.
Sun Refining & Marketing Co.	Chevron Corp.
Star Enterprises	Sunoco Inc.
Citgo Petroleum Corp.	Citgo Petroleum Corp.
Marathon Oil Co.	Flint Hills Resources (Koch Industries)
Koch Refining Co.	Tesoro Corp.
Tosco Corp.	Saudi Aramco
Arco	Lyondell Chemical Corp.
Conoco Inc.	Total SA
Texaco Refining & Marketing Co.	
Ashland Petroleum Co.	
Phillips Petroleum Co.	
Clark Oil & Refining Corp.	
Lyondell-Citgo Refining Co.	
Phibro Refining Co.	
Coastal Refining & Marketing Co.	
Fina Oil & Chemical Co.	
Unocal Corp.	
Mapco Petroleum Inc.	
Diamond-Shamrock Corp.	
91 refineries and 13.02 billion b/cd	88 refineries and 15.72 billion b/cd

*Companies with 200,000+ b/cd crude oil capacity.
Source: OGJ 1995 and 2006 refinery surveys

US refining oligopoly?

Is it time to set the clock back and revisit 1911? Hardly.

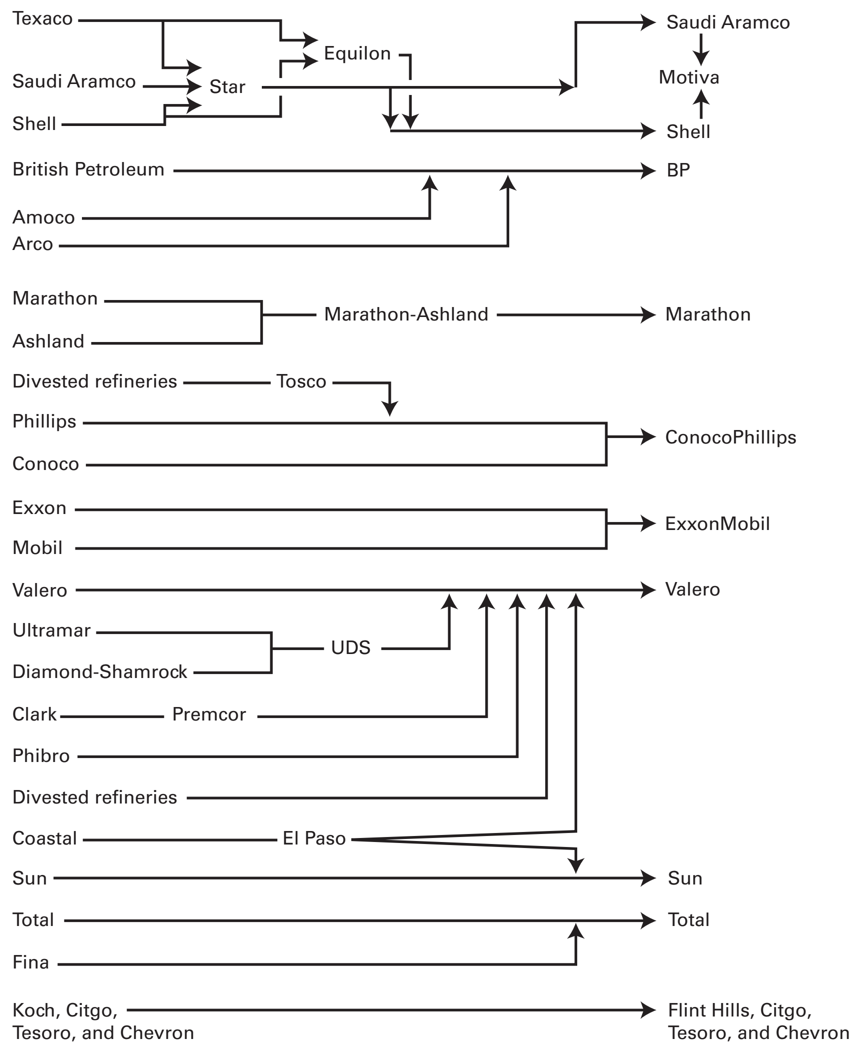
By any contemporary measure, the US refining industry participants are poorly positioned to exert oligopolistic (much less monopolistic) control over the commercial aspects of crude oil or products. One of the favorite measures of concentration and control is the concentration ratio (CR). The CR is the sum of the percentages of the market shares of the largest four (sometimes five, denoted CR_4 or CR_5) companies. Economists consider a CR_4 of over 50% a tight oligopoly and a CR_4 of 25-50% a loose oligopoly.[2] In the case of US refining, the CR_4 is 46%.

The trouble with the concentration ratio is that it doesn't put the top companies in context. Certainly if one of the top four refining companies held 40% and the other three held 2% each, that would have a different implication than if each held 11-12%. A better measure is the Herfindahl-Hirschman Index (HHI).

This criterion captures in a single number the relative size and distribution of the companies in a market. The formula is relatively simple: HHI is the sum of the squares of the market shares of each participant. For US refining

Refiners' realignment, 1995-2006

Fig. 2



US concentration measures

Table 2

Areas (No. of refineries)	Concentration ratio, %[1]	HHI[2]
Gulf-Atlantic Coast (53)	25	878
Midwest (19)	85	2,713
Great Plains-Rockies (32)	35	930
West Coast (20)	44	1,425
US	**46**	**768**
Midwest-Gulf Coast	48	696

[1]The sum of the percentages of the market shares of the largest four companies. [2]The Herfindahl-Hirschman Index.

companies in 2006, the HHI would be:

$13.3^2 + 12.7^2 + 10.6^2 + 8.5^2 + ...)$

Adding the squares of the shares of the remaining 47 companies gives the sum of 768, the US refining industry's HHI.

The US Department of Justice holds that: "Markets in which the HHI is between 1,000 and 1,800 are considered to be moderately concentrated, and those in which the HHI is greater than 1,800 points are considered to be concentrated."[3] In 2007, the US refining industry is well below those standards.

Some concerned economists might well point out that the US is not just one market but a composite of several. To examine that, the same data can be disaggregated. Most in the oil products industry will agree that the US refining markets fall into four logistical areas:

- *The Gulf-Atlantic Coast*, with 53 refineries. Granted, that is a broad geographic area. But the refineries on the Gulf Coast compete with East Coast refineries by shipping millions of barrels per day of oil products east and northeast through the Colonial and Plantation pipelines and by barge and tankers. In addition, imports of foreign oil products pour in on both coasts.
- *The Midwest*, with 19 refineries. This includes facilities from Memphis north to Minnesota and east to West Virginia.
- *The Great Plains and Rocky Mountains*, with 32 refineries. This sparse mid-America area is hardly a single market, but agglomerating these refineries makes more sense than aggregating by state where, for example, El Paso would be included with (but logistically unrelated to) Houston and the same would apply for Kansas City with St. Louis.
- *The West Coast*, including California, Washington, and Oregon, with 20 refineries.

This market demarcation seems to make more sense than the commonly used Petroleum Administration for Defense Districts (PADDs), an artifact of World War II that was originally concerned with defense.

Placing each refinery in the Lower 48 states in one of these four areas gives the CR_4s and HHIs shown in Table 2.

Three of the four market areas have HHIs and CR_4s below the threshold of concern. The Midwest area, however, exceeds the guidelines by a wide margin—at least until additional logistical data is considered: The Energy Information Administration reports that over 1 million b/d of oil products enters this area from the Gulf Coast—nearly 25% of the total market supply.[4] To reflect this actuality, a logistical system can be constructed by combining the Midwest with the Gulf Coast refineries. In that case, double counting with the Gulf/Atlantic Coast aside, the revised HHI for the "Midwest/Gulf Coast" is but 696, and the CR_4 drops to 48%, both below worrisome levels.

What does this all mean? Despite the tumultuous concentration of 1995-


Just another day in the office
HYDRO

2006, the refining industry in the US, or even in its logistical submarkets, is still less concentrated than what economists accept as important benchmarks. For that reason, mergers and acquisitions, such as Tesoro's acquisition of Shell's 100,000 b/cd Wilmington, Calif., refinery the first of this year, may continue for some time as companies seek to achieve economies of size and scope, and others choose to continue exiting the business.[5] ✦

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The author

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House energy reform will be open, Rahall pledges

Nick Snow
Washington Correspondent

US House Natural Resources Committee (NRC) Chairman Nick J. Rahall (D-W.Va.) said on May 23 he is committed to an open and deliberate process in considering federal energy reforms contained in a bill that he introduced a week earlier. On May 16 Rahall introduced HR 2337, entitled the Energy Policy Reform and Revitalization Act (OGJ Online, May 16, 2007). The bill's four titles include provisions that potentially would, among other things, repeal parts of the 2005 Energy Policy Act (EPACT), increase federal reclamation bond and produced water handling requirements, and limit federal oil royalty in-kind (RIK) payments to Strategic Petroleum Reserve purchases.

Republican NRC members protested that oil and gas industry groups, which have strongly criticized the bill, were largely excluded from its development. Rahall responded that they could submit comments before the committee returns to mark up the bill following the Memorial Day recess.

Presidents of three gas industry groups expressed deep concerns about the bill in a May 22 letter to Rahall. Barry Russell of the Independent Petroleum Association of America, Skip Horvath of the Natural Gas Supply Association, and Donald F. Santa of the Interstate Natural Gas Association of America said HR 2337 "would move significant and much-needed natural gas supplies out of reach while making it more difficult to build new pipeline infrastructure."

In a statement distributed to reporters before the hearing, the American Exploration & Production Council called the bill "a prescription for slowing natural gas exploration, reducing production, and increasing prices."

'Weren't invited'

Oil and gas industry groups also said they were being excluded. "We're here, but we weren't invited to testify," Marc W. Smith, executive director of the Independent Petroleum Association of Mountain States, told OGJ before the hearing began.

Representatives of federal agencies involved in resource management and development made up the first panel of witnesses. Rahall said he acceded to requests from the committee's Republican minority to let a second panel of presidents of two organizations representing energy consumers testify.

John Engler of the National Association of Manufacturers and James L. Martin of the 60-Plus Association, a senior citizens advocacy group, separately questioned the wisdom of imposing more restrictions on domestic energy production as prices are rising.

As he welcomed the first panel (US Bureau of Land Management Deputy Director Henri Bisson; Minerals Management Service Deputy Director Walter Cruickshank; Melissa Simpson, deputy undersecretary for natural resources and environment at the US Forest Service; Vickie VanZandt, senior vice-president for transmission services at the Bonneville Power Administration, and Timothy R.E. Kenney, deputy assistant secretary for oceans and atmosphere at the National Oceanic and Atmospheric Administration), Rahall quipped, "I am probably the first committee chairman to hold a hearing consisting only of witnesses who are hostile to his position."

But he also said the Natural Resources Committee was taking a different approach to developing legislation than it used in recent years. "During the 6 years that I served as the ranking member, the practice was for the majority to toss out energy bills a day or two before a markup, with no hearings, affording the members of this committee little time to completely understand what they were voting on," he said.

In contrast, he continued, HR 2337 was introduced a full week before the hearing. "The record will be open for submitted testimony and, with the House not being in session next week, interested parties are afforded even more time to dissect provisions of the legislation before it is marked up,"

Rahall said.

He said the primary witnesses were limited to representatives of the current presidential administration to give it "the opportunity to testify in person in the event that it wanted to defend its position with respect to specific provisions or to offer constructive advice in its capacity as the entity that would have to implement provisions of the bill should it become law."

As they testified, however, the federal witnesses generally said their agencies needed more time to consider the bill's potential impacts and would have to submit written comments later.

Defends provisions

In his opening statement, Rahall also defended the bill's provisions, which he said grew out of 13 committee and subcommittee hearings. They showed that the federal government is not receiving a fair return on energy produced from public resources and that recreational and agricultural activities are being harmed, he said.

"I have heard the allegation that this bill repeals the Energy Policy Act of 2005," Rahall said. "There are 530 sections in that act, 84 of which fall under this committee's jurisdiction. Of those 84, HR 2337 amends only seven of those provisions."

The EPACT provisions that would be repealed include a requirement for BLM to process onshore drilling permit applications in 30 days, suspension of permit processing fees, and initiation of a process that could lead to oil shale and tar sands development. Rahall said the hearings also revealed that surface landholders need more rights in federal split-estate situations and that produced water uses should be restricted.

But his strongest attack was on MMS's RIK program, which the agency says has reduced operating expenses and increased revenues but which Rahall said is plagued with scandal. "According to media reports, the Justice Department has launched a criminal investigation into the activities of top officials involved with the royalty-in-kind program. The inquiry appears to focus on the cozy relationship between these officials and those in industry who seek contracts from them," he said.

An MMS spokesman confirmed to OGJ that the Department of Justice is investigating two possible ethics violations in the RIK program following a probe by Department of Interior's inspector general and that the program's director, Gregory Smith, is retiring effective May 26.

HR 2337 would require MMS to conduct a minimum of 550 oil and gas lease audits each fiscal year. In his testimony, Cruickshank said compliance reviews, which MMS uses as a less expensive alternative to full audits on high-volume properties, collected \$3.27/\$ spent from fiscal 2003 through 2005, compared with \$2.07 collected through audits.

Committee Democrats generally applauded the bill. "It's a good place to start to assure we get a fair return from production on public lands. Compared to other parts of the world, where assets can be seized, our government extracts relatively little from those who produce oil and gas on its holdings in a much more secure political environment," said George Miller of California.

Others called for a more cautious approach. "Repealing the 30-day drilling permit decision deadline could have consequences. Maybe 30 days isn't the right time period, but leaving it open-ended could be problematic," said another Californian, Jim Costa.

Dan Boren of Oklahoma said he backed Rahall's commitment to an open process but added that domestic drilling has grown and production will follow soon since EPACT's enactment. "I'm glad this committee is taking its oversight responsibilities seriously, but this bill would increase energy costs and place a greater burden on the poor, something that Democrats traditionally oppose," he said.

Some Republicans said the bill is a mistake. Chief minority member Don Young of Alaska said it would make domestic energy more expensive and less available. Doug Lamborn of Colorado said, "Section 306 raises disturbing implications of federal interference in groundwater, which traditionally has been handled by states."

Rahall reiterated that the bill could change. "Very few introduced measures are perfect. I do not view HR 2337 as being written in stone," he said. ✦

Senate Democrats promise bill with 'gouging' measure

Nick Snow
Washington Correspondent

US Senate Democrats said they will soon bring an energy bill to the floor that will make oil product price manipulation a federal crime, mandate more efficient government offices and motor fleets, increase biofuel supplies, and accelerate market entry of other alternative fuels.

Majority Leader Harry Reid (D-Nev.) said he originally planned to bring the bill before the full Senate immediately after the week-long Memorial Day recess but decided to delay it for a week to allow full debate on immigration legislation.

The package will contain bills from the Energy and Natural Resources, Environment and Public Works, and the Commerce, Science, and Transportation committees, Reid said in a May 23 briefing.

He was joined by Jeff Bingaman (D-NM), who chairs the Energy and Natural Resources Committee; Barbara Boxer (D-Calif.), who chairs Environment and Public Works; John F. Kerry (D-Mass.), who chairs Commerce, Science, and Transportation's Science, Technology, and Innovation Subcommittee; and Maria Cantwell (D-Wash.), a member of the Energy and Natural Resources and the Commerce, Science, and Transportation committees.

Despite a backdrop proclaiming "Energy Independence," Reid said the bill, designated "The Renewable Fuels, Consumer Protection, and Energy Efficiency Act of 2007," is a starting point. "We think anything we do should have some effect on the gluttony of the oil companies. The mere fact that we're talking about legislation should get their attention," he said.

'Sends a message'

Noting that the US sent $250 billion overseas in 2006 to import crude and products, Reid added: "The mere fact we're moving legislation on the floor should send a message to oil cartels."

Cantwell said Reid notified six committee chairmen in January that energy would be a top Senate priority in 2007. "It is critically important, as we research and develop cleaner energy alternatives, that consumers are protected, particularly during supply emergencies," she said on May 23.

Later that afternoon, the House passed its own bill directed against alleged oil-product price manipulation, HR 1252, originally introduced by Rep. Bart Stupak (D-Mich.), by a 281-184 vote.

Cantwell's bill was added to motor vehicle fuel efficiency legislation that passed the Senate Commerce Committee on May 8 and will be part of the energy legislation package due on the floor in June.

That bill will offer energy steps more easily achieved than the bigger ones that need to be taken to solve the US energy dilemma, Boxer said.

"It's low-hanging fruit that can be picked right now," she said. "We have decided that the federal government should be a model of energy efficiency by retrofitting buildings that it owns and office space that it leases. I'm also excited that we have the administration's support in offering matching funds to states and cities for similar efforts. And the 60,000 cars which the federal government buys each year will have to be as fuel-efficient as possible."

Bingaman said the package will contain language from the energy and commerce committees dealing with cellulosic ethanol, energy efficiency, and carbon sequestration. Provisions requiring creation of a power generation portfolio of renewable sources, lighting efficiency, and additional renewable fuel incentives could be added on the floor, he said.

"This will be one of the most significant debates we have in Congress this year," said Kerry, who noted that the commerce committee's contribution to the package was its motor fuel efficiency and oil product price-gouging bill. ✦

WATCHING GOVERNMENT

Nick Snow, Washington Correspondent

Meanwhile, on the OCS…

The e-mail message arrived the morning of May 23. Blaming "unforeseen logistical reasons," it said US Reps. John E. Peterson (R-Pa.) and Neil Abercrombie (D-Ha.) would not hold a scheduled press conference on reintroduction of their National Environment and Energy Development (NEED) Act the next day.

It's also possible the press conference was postponed because of so much other oil and gas activity in Congress. On May 23 alone, the House Natural Resources Committee held a hearing on HR 2337, which, to put it mildly, is controversial.

"I cannot recall a bill that has made so many organizations unhappy, including 34 fish and wildlife groups," committee member Harry E. Brown Jr. (R-SC) observed. That afternoon, the full House passed HR 1252, which would give the Federal Trade Commission power to investigate gasoline price-gouging allegations. And in the Senate, Democratic leaders described a legislative package that bundles bills from several committees.

Lost in shuffle?

It wouldn't be surprising if Peterson, Abercrombie, and their staffs wondered if their bill might be lost in the shuffle. One of its key provisions aims to expand natural gas production from the US Outer Continental Shelf. Conventional wisdom holds that passage of a bill late in 2006 to increase leasing in the eastern Gulf of Mexico is enough for now.

Peterson, particularly, disagrees. At every opportunity, he mentions how much of the OCS is still off-limits and how gas from that acreage could lower US prices and remove a competitive disadvantage hurting American manufacturers.

This wouldn't be the first time Peterson defied conventional wisdom. Two years ago he gave a floor speech calling for more OCS gas leasing when many other people considered the idea futile.

He's not alone this time. In discussions of other bills that are seemingly unrelated, talk occasionally moves back to the OCS. At the hearing on HR 2337, which primarily deals with onshore federal resource management, Brown asked five government witnesses if they thought gas could be produced safely 50 miles offshore.

Heavy reliance

Noting that his district includes coastal communities, the South Carolinian said, "I just don't believe we can keep depending on the Gulf Coast states to continue furnishing the country with so much of its energy."

Industry officials see continued opposition. A week earlier, at the Deloitte 2007 Energy Conference, Vouter de Vries, vice-president of finance in Shell Energy Resource Co.'s E&P Americas division, said efforts began in Congress to undo the US Minerals Management Service's new 5-year plan within days of its announcement.

Asked if leases restricted to gas might work, De Vries replied, "It's hard to determine whether you're seeing oil, gas, or water when you run seismic. Virginia is apparently interested, however, and we're encouraged because the idea is coming from a state." ✦

US House cites similar

Nick Snow
Washington Correspondent

Cost-cutting efforts created a culture at BP America Inc. that led to compromises of systems integrity at its Alaska North Slope oil-gathering pipelines and of workplace safety at its Texas City, Tex., refinery, witnesses and federal lawmakers agreed on May 16.

"Virtually all of the seven root causes identified for the Prudhoe Bay incidents have strong echoes in Texas City," said US Chemical Safety Board Chairwoman Carolyn W. Merritt. She had been asked by the House Energy and Commerce Committee's Oversight and Investigations Subcommittee to compare Booz Allen Hamilton's analysis of the oil line leaks for BP with CSB's investigation of the Mar. 23, 2005, explosion and fire at the refinery.

"Both reports point to the significant role of budget and production pressures in driving BP's decision-making—and ultimately harming safety.... Both investigations found deficiencies in how BP managed the safety of process changes.... Other common findings included flawed communication of lessons learned, excessive decentralization of safety functions, and high management turnover," Merritt told the subcommittee during a hearing on causes of the oil leaks.

Rep. Bart Stupak (D-Mich.), the subcommittee's chairman, also found similarities. "One of the primary findings in the CSB report was that 'cost-cutting and budget pressures from BP group executive managers impaired process safety at Texas City'.... Similarly, documents made available to this subcommittee suggest that BP field managers were under extreme pressure to cut costs in Alaska," he said in his opening statement.

Leak causes revisited

Stupak said the hearing originally

problems with BP line, refinery

was intended to update corrective actions that BP, as well as state and federal agencies, were taking at Prudhoe Bay. Documents that BP recently supplied to the full committee made it necessary to revisit the issue of what caused the leaks, he said.

"Some of these documents were actually available to BP officials before the Sept. 6 hearing, yet BP failed to disclose this information. These documents show that cost-cutting pressures on Prudhoe Bay operations were severe enough that some BP field managers were considering reducing or halting a range of actions related to preventing or reducing corrosion," Stupak said.

BP America Chairman Robert A. Malone said cost-cutting pressures helped create problems at Texas City and Prudhoe Bay. But he also suggested that the ANS oil-gathering line leaks may have been caused more by employees placing too much confidence in corrosion inhibitors' effectiveness.

"Booz Allen Hamilton concluded that in the absence of better risk assessment processes, budget increases alone would not have prevented the leaks. Our own work has revealed that the workforce did not have an adequate process to challenge their own assumptions," he said in his written statement.

In questioning Malone, Stupak noted that the BAH report concluded that because BP Alaska's health, safety, and environment program focused exclusively on workplace safety, its major accident risk and hazard assessments did not consider corrosion risk on the oil transit lines (OTL).

"These risk assessment approaches might have identified the changing profile of the OTL created by the changing operating conditions," the report says. Stupak said falling production at Prudhoe Bay reduced pressure and added produced water to what was going through the gathering lines, making corrosion inhibitors much less effective.

Malone said the BAH report concluded that the leak occurred because there was no formal risk-assessment process that considered the oil field's changing operations and conditions. "It suggests that if we had given them more money, they wouldn't necessarily have used it because they were confident the system they were using was working," he told Stupak.

BP's reforms

Since becoming BP America's chairman in July 2006, Malone said he has installed managers in Alaska as part of a series of reforms across all of BP PLC's US division.

Merritt and three other government witnesses—Richard Fairfax, enforcement programs director at the US Occupational Safety and Health Administration; Stacy Gerard, acting assistant administrator and chief safety officer at

Watching the World

Eric Watkins, Senior Correspondent

Russia goes after TNK-BP

Have we spoken enough of the Russian government and its depressing effects on the international oil and gas industry? Apparently we haven't, given recent events which portend further ills for all concerned parties.

Last week, Russian regulators were poised to begin discussing the withdrawal of the license held by BP's Russian venture TNK-BP to develop massive Kovykta gas field.

One report said the long chess match over Kovykta appeared to be entering its end game when a Siberian court claimed it hadn't the jurisdiction to hear a suit from TNK-BP challenging regulators' claims that it was not producing enough gas from the field.

As a result, Russia's natural resources ministry said it would "very likely" discuss whether to revoke the company's license.

Rocket science?

What does that really mean? Well, it doesn't take rocket science to understand that the move would create the need for a new tender for the field. Nor, given the kinds of money now being paid for natural gas, is it any surprise that a new tender would be won by Gazprom, Russia's state-controlled natural gas monopoly.

Indeed, a number of observers see the attack on Kovykta as part of a broader move to return Russia's oil and gas deposits to state control.

The Russian government is no stranger to such moves, nor should anyone else find them surprising. In April this year, Gazprom completed its takeover of Royal Dutch Shell PLC's Sakhalin-2 oil and gas venture in a deal that leaves the state-controlled gas giant with one share more than a 50% stake in the project.

The Sakhalin-2 settlement came after a bruising government campaign targeting the formerly Shell-run project for alleged ecological violations on the far eastern island. Shell caved in to government pressure last November when it agreed to cede control to Gazprom for $7.45 billion.

Uncertain supplies

Under the deal, Shell is to hold a 27.5% stake in Sakhalin Energy, which runs the project, while Japan's Mitsui and Mitsubishi will hold a 12.5% stake and a 10% stake respectively. Regardless of stakes, though, the deal left the Japanese owners—as well as their government—uncertain about the security of their gas supplies. In Europe last week, similar concerns were voiced over plans approved by the Russian government for an oil pipeline that could enable the country to bypass Belarus and tighten Moscow's grip over much of the EU's energy supplies.

Analysts said the new spur could eventually end shipments through the Druzhba, or Friendship, pipeline via Belarus to Poland, Hungary, Slovakia, the Czech Republic, and Germany.

Would the Russians use such a stranglehold?

"Russian diplomacy is quite strong, quite experienced, and they are trying to divide us. That's obvious," said Gediminas Kirkilas, prime minister of Lithuania. His experience speaks volumes: Russia has halted shipments of crude oil to Lithuania's Butinge terminal for the past 10 months. ✦

the US Pipeline Safety and Hazardous Materials Administration (PSHMA); and Jonne Slemons, coordinator of the Petroleum Systems Integrity Systems Office (PSISO) in Alaska's oil and gas division—said BP's new Alaska team has been much more cooperative.

Rep. Joe Barton (R-Tex.), the Energy and Commerce Committee's chief minority member, was more skeptical. "Everything that's in these documents suggests that BP is trying to do the right thing in public while fighting like a tiger in private. These folks who represent state and federal regulatory authorities can do their jobs to the extent of the law, but we're just rearranging deck chairs if BP refuses to change its attitude," he said.

As he examined BP America's operations soon after taking the helm, Malone said, "The most striking thing to me was that we didn't have rigorous process safety management embedded in our culture. It will take years to do this. But as I've traveled to Texas City and Alaska, I've been impressed with the teams' commitments to getting the job done."

Regulators' actions

In response to the 2006 Prudhoe Bay oil-gathering lines' leaks and shutdowns, Alaska established PSISO as the lead state oversight agency for oil and gas facilities and as coordinator with federal entities, said Slemons. PSISO is conducting a regulatory gas analysis to avoid duplication of efforts while trying to close gaps, and is requiring well operators to implement quality assurance programs, she told the subcommittee.

"Alaska is the only state in the country to require industry to allow regulator access to operator facilities in order to ensure compliance with their own maintenance programs. We look forward to breaking this new ground and to cooperative efforts with our federal partners," she said.

Gerard said in response to the federal Pipeline Safety Act reauthorization—passed by the 109th Congress in December—PHMSA is proceeding with rulemakings that include extending full regulatory protection to low-pressure pipelines such as the BP ANS oil-gathering systems. The US Department of Transportation agency also is improving its coordination with Alaska's regulators, she said.

"We also have progress to report concerning our oversight of BP Alaska. Based on our ongoing monitoring of its activities and pipeline inspection results, we have increasing confidence in engineering, operations, and maintenance of the existing transit lines. BP Alaska also has begun to replace the Prudhoe Bay transit lines and is beginning to address management problems that contributed to the failures they experienced last summer," she said.

Of the 16 miles of Prudhoe Bay oil transit lines that BP intends to replace by the end of 2008, Malone said, 8 miles were completed by the end of April after more than 600 workers worked through the winter without a lost-time injury. The new system will use insulated carbon steel with a special epoxy external coating and will have a new above-ground vertical support structure, permanent pigging facilities, and a highly sensitive leak detection system, he said.

Fairfax said OSHA imposed a $21 million penalty, the largest in its history, against BP Products following the Texas City explosion and fire. It also issued an enhanced enforcement alert to its regional offices and state partners, began inspections of the company's four other US refineries, and fined BP Products another $2.4 million based on 32 violations, he said.

OSHA program launched

"As a result of the Texas City accident, OSHA began evaluating its data on facilities and catastrophes and determined that refineries experienced more of these problems than the next three industry sectors combined. Accordingly, OSHA is preparing to launch a National Emphasis Program (NEP) for petroleum refineries focusing on the Process Safety Management standard," he said.

The federal workplace safety agency plans to conduct enforcement inspections at all 81 refineries under its jurisdiction by the end of 2008 and to encourage its state partners to implement its NEP or create their own emphasis programs, Fairfax said.

Subcommittee member Gene Green (D-Tex.) suggested that federal safety requirements need to be extended to contractors and their employees. Earlier this year he introduced HR 141, which would require companies to report contractor employees' injuries and deaths to OSHA in the same way they report injuries and deaths of their own employees.

Green said when he was visiting another company's refinery following the Texas City blast and fire, he noticed several contractors' temporary structures still were close to process units (a situation that contributed to the deaths and injuries at the BP Products refinery). When Green asked officials of the other company why, he said, they responded, "We haven't got around to moving them yet."

Green said, "Unfortunately, I do not believe all the lessons learned either from the leaks on the North Slope or the accident at Texas City have been applied yet. Incidents such as the ones we're discussing today breed more public mistrust of the industry and suggest a disregard by some companies for the safety of their workers."

Stupak told reporters following the hearing that he thought Malone was as forthright as he could be, considering he's running a multibillion dollar operation. But he also suggested that a cost-cutting culture still pervades BP America.

"You don't change that quickly. There are several layers between workers in the field and [Malone], and I'm certain it will take time for them to grow confident that they can bring safety matters which could cost money to the company's attention," the subcommittee chairman said.

Stupak also said he believes the subcommittee will need to hold another hearing on BP's ANS oil-gathering lines within the next 6 months. ✦

Government, industry prepare for 2007 hurricane season

Nick Snow
Washington Correspondent

New procedures are being implemented to better protect Gulf of Mexico oil and gas operations during the coming hurricane season, federal government and industry officials said.

Measures range from requiring all structures to have global positioning systems to restricting operations of mobile offshore drilling units that have not been brought up to new standards, they told reporters during a May 30 briefing at the US Dept. of the Interior.

"We're preparing for a very, very active hurricane season," said Walter D. Cruickshank, deputy director of the US Minerals Management Service. He noted that a week earlier, the National Oceanic and Atmospheric Administration forecast 13-17 named storms during the Atlantic hurricane season, with 7-10 of those becoming hurricanes and 3-5 hurricanes reaching Category 3 strength or higher.

MMS is implementing seven operational enhancements to further clarify special engineering practices and reporting procedures on all offshore structures from mobile offshore drilling units (MODUs) and jack ups to existing and new fixed platforms, said Cruickshank. On June 1, the hurricane season's opening day, the DOI division also will activate a new hurricane information website with current storm information and updated production and evacuation information, he said.

Simultaneously, the American Petroleum Institute has published three interim documents that apply the latest understanding of environmental conditions in and around the gulf to better protect offshore facilities from hurricanes, API Pres. Red Cavaney said.

'Metocean' impacts

Hurricanes Ivan in 2004 and Katrina and Rita in 2005 produced higher waves and stronger winds than anticipated in deeper areas, moving the industry away from viewing the gulf as a uniform body of water, he explained. Recognizing a central portion, the "metocean," as a gathering spot for water currents that can strengthen storms led API to reassess applicable recommended practices, Cavaney said.

API published three interim documents for the 2006 hurricane season covering operation and construction of both MODUs and fixed and floating production platforms. The interim documents announced on May 30—dealing with hurricane condition data, offshore structure design, and assessment of existing offshore structures—are expected to become final recommended practices in 2008.

"Meanwhile, our companies are refining and distributing fuel at record levels after recovering from damage sustained during the 2004-05 hurricanes. For 2007, refiners and marketers continue to work with authorities to clarify priorities for power restoration critical to restarting operations and, where possible, to provide emergency power generation to avoid significant disruption to fuel delivery and distribution," Cavaney said.

The GPS requirement is one of several steps that will improve tracking of equipment and evacuation of employees, noted Rear Adm. Wayne Justice, enforcement and incident management director at the US Coast Guard. "Assuring that two agencies can communicate, even if one has to move to another location, is critical. We have shown we can do that," he said.

Cruickshank said that after the 2005 hurricanes forced MMS to temporarily relocate its Gulf Coast headquarters to Houston from New Orleans, its five offices in the region now have independent communications systems so they can still function if one has to shut down during an emergency.

"New practices have suggested that MODU operators increase the number of mooring lines from 8 to 12," he said. MMS has issued notices to operators in the gulf providing guidance for meeting new requirements, which includes following API's recommended practices, he said.

Possible restrictions

"The costs could be substantial," observed Elmer Danenberger, engineering and operations division chief at MMS. "Several mobile drilling rigs won't be able to operate in parts of the gulf during hurricane season because they don't have new equipment. Up to 20% of the existing MODU fleet could be affected."

New standards primarily involve top-side equipment because subsurface systems came through the 2005 hurricanes with relatively minor damage, he told reporters following the briefing. The Mars platform experienced problems when wind tore a derrick loose and sent it into the water, creating a cascade that jarred the entire structure, he said.

Platforms now are being designed so decks are about 25 ft higher at 75 ft above the surface, Danenberger said. Older platforms still are likely to survive, based on their performances during the 2005 hurricanes, but the newer ones are being built to sustain less top-side damage, he said.

Offshore pipelines have developed alternative routes since the two Category 5 storms, while some platforms have built systems that make it easier to unload stored crude onto barges, added MMS Associate Director Chris Oynes.

Onshore, said Cavaney, "Pipeline companies have taken a variety of steps, including onsite backup electric power generation capability, improving communications systems to support continued operations, and working with vendors to preposition food, water, and transportation, and plan for other emergency supplies and services."

"We think that with the improvements that have been made to new and existing facilities that they'd be able to better withstand what they had to endure in 2005," said Cruickshank, "although it's never smart to second-guess Mother Nature," he added. ✦

WCSB STRUCTURAL DOMAINS—1

W. Canada structured belt given high gas potential

J.H.N. Wennekers
Consulting Geologist
Calgary

Many discoveries will be made in the future if the oil and gas industry takes on increased risk scenarios, moves farther into the mountains, drills deeper targets, and pursues shallow resource plays.

It is projected that 100+ tcf of natural gas awaits discovery in the structured belt of the Western Canada Sedimentary basin (WCSB).

There are 2,000+ undrilled, multi-target structures with known and new play types, including fractured rock bodies and high pressure-high temperature deep carbonate buildups.

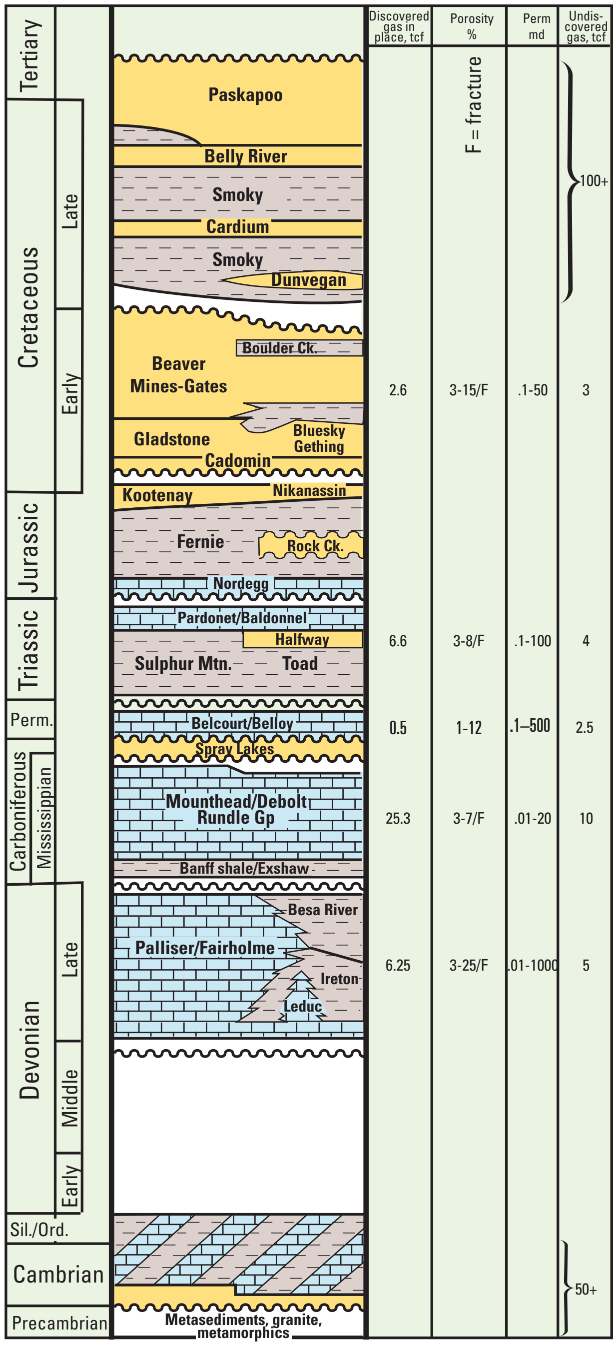
Estimated numbers of undrilled structures in the structured belt are: 50+ Precambrian, 5+ large Cambrian-Ordovician carbonate buildups, 300+ Devonian, 400+ Mississippian, 200+ Permian, 300+ Triassic, and 5,000+ post-Triassic.

The 5,000+ shallow to medium depth structures contain resource plays in sequences of coal, sandstone, siltstone, and shale alternating and interbedded with carbonaceous sandstone-siltstone-shale 6,000+ ft thick.

Future exploration will only be successful when stress and strain are understood and when structural geology is given its appropriate place in exploration teams. Seismic interpret-

WCSB FORMATIONS AND RESOURCES

Fig. 1



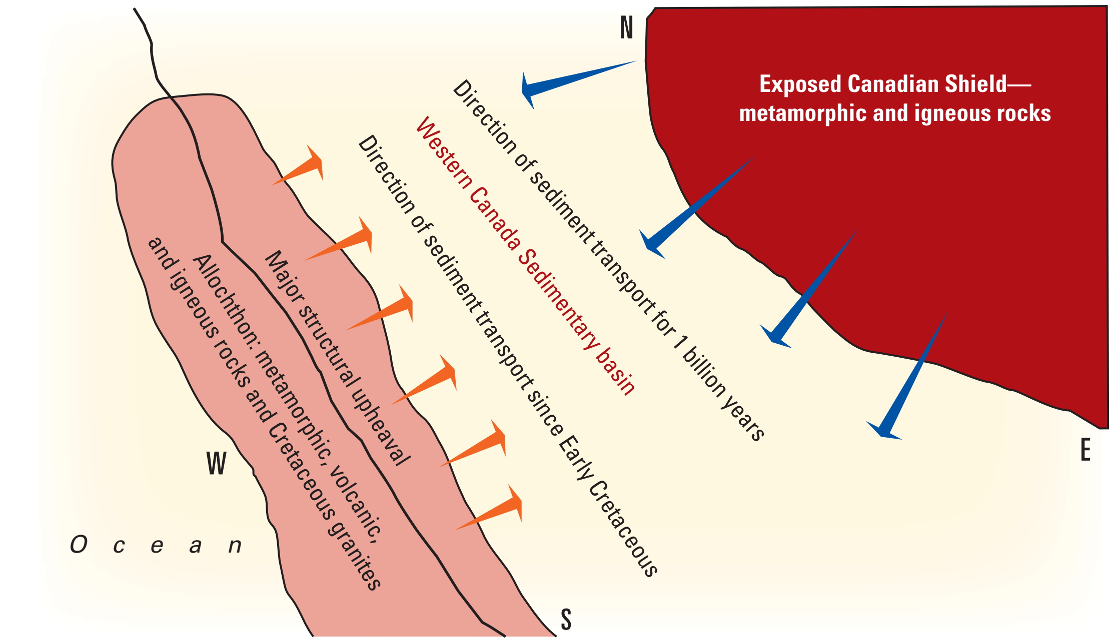
ers create geometry form maps from impedance similarity recognition and mapping. They should not take the place of structural geologists as unfortunately so often occurs. The latter should interpret the geometry form maps and prepare evolution of forces and strains.

Drilling has discovered 41 tcf of marketable gas, including 8+ tcf in strike-slip structures and 33 tcf in thrusts and gravity slide structures, in the structured belt.

Described in this four-part article is a redefinition of force fields that formed the WCSB structured belt. Subduction zones did not cause the belt. If one ever existed it was overridden by a large foreign rock body that slammed into and overrode the Western Canadian Shield. In the process it ploughed E the sedimentary section of the WCSB.

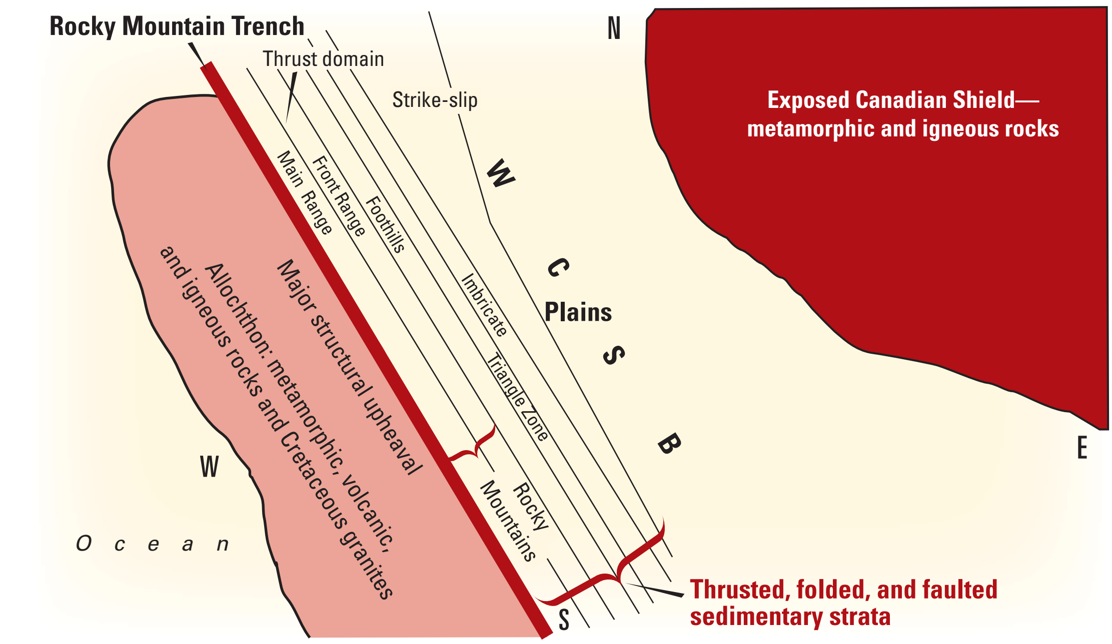
Periods of sedimentation in Western Canada

Fig. 2



Structured belt in Western Canada

Fig. 3



A series of massive composite thrusts developed. The oldest ones are in the W and the youngest in the E. Each of these acted as a rock plough, pushing the sedimentary section ever eastward.

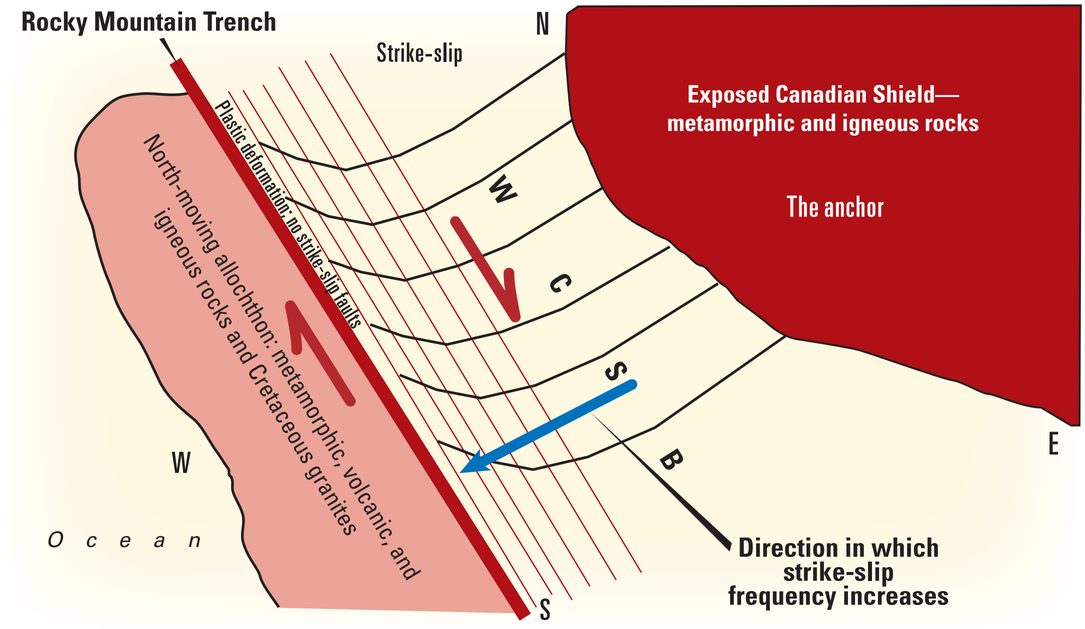
This assessment is based on regional seismic transects, surface geology, and well data. Six exploration/structural domains are recognized. Structures were formed by simultaneously acting major compression/thrusting, gravity sliding, and transpression/shear force fields.

The structured belt of the WCSB probably is one of the most complex "structures" in the world, probably too taxing for most that explore it for hydrocarbons. It is a structural enigma, not just another thrust belt.

This redefinition of forces changes exploration target definitions and enables recognition of potentially huge new resource plays.

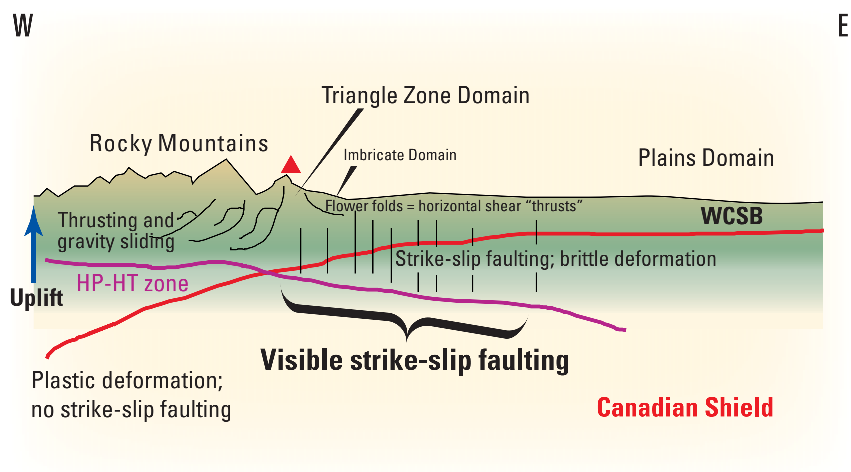
ALLOCHTHON'S COLLISION CREATES STRUCTURED BELT

Fig. 4



STRIKE-SLIP FAULT DEVELOPMENT DEPENDS ON DEPTH AND TEMPERATURE

Fig. 5



Introduction

For more than a billion years, the western Canadian portion of the North American continent was a receptacle of sediments (Fig. 1). The WCSB is one of the world's most prolific hydrocarbon basins.

Sediments mainly were sourced from the east (Fig. 2) by erosion of igneous-metamorphic basement rocks of the Canadian Shield. Sediments include Precambrian to Cambrian mainly siliciclastics (>3 miles thick) overlain by Cambro-Ordovician to Mississippian-Permian carbonates and shale (2 miles thick) and Triassic siliciclastics and carbonates (0.5 mile).

A second sediment source area emerged with massive structural upheaval in the W in post-Triassic time. A large foreign body slammed into and overrode the western Canadian Shield. From then onward, the WCSB received sediments from E, S, and W. Post-Triassic strata (3 miles thick) include thick sections of Cretaceous siliciclastics with abundant Barnett-like shale-siltstone and coal seams, representing an untapped major gas resource play.

The WCSB sedimentary section contains many basinwide unconformities, reflecting periods of worldwide tectonic upheaval. Its western reaches were deformed into a structured belt by the Nevadan, Sevier, and Laramide orogenies.

In British Columbia, the Rocky Mountain Trench stretches from the US border to the Yukon. It separates a region formed primarily of plutonic, volcanic, and metamorphic rocks (allochthon) intruded by numerous Cretaceous granites in the W from the Laramide Rocky Mountains and Foothills comprised of folded and faulted sedimentary rocks (structured belt of the WCSB) in the E.

The structured belt (Fig. 3) encompasses the Rocky Mountains, Foothills, and the western structured portion of the Plains of western Alberta and Northeast British Colombia. It covers more than 100,000 sq miles and extends more than 1,000 miles in a northwesterly direction with a width of 100 miles from the Alberta/Montana border in the S to the line between British Columbia and the Yukon Territory in the N.

This region is bordered in the E by the "undisturbed" Plains sedimentary section (Precambrian to Tertiary) that extends E to igneous and metamorphic outcrops of the Canadian Shield. To the W, it is bordered by the Rocky Mountain Trench.

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Commonly, it is mistakenly assumed that subduction created the structured belt of the WCSB. Instead, it was a N-moving elongated land mass (allochthon, Fig. 4) an estimated 300 miles wide, 2,000 miles long, and 20-30 miles thick that collided with and slid onto the W portion of the massive Canadian Shield, core of the North American continent. It includes most of British Columbia and moved parallel to its NW-SE long axis, guided by ancient subsurface oceanic crustal features.

Any structured belt associated with subduction and passive continental margin was overridden by this N-moving continental rock body. It scraped over the shield like a massive rock plough. It ploughed E the sedimentary section of the WCSB.

A series of massive composite thrusts developed. The oldest ones are in the W and the youngest in the E. Each of these acted as a rock plough pushing the sedimentary section ever farther E. This assessment is based on regional seismic transects, surface geology, and well data.

Six exploration/structural domains are recognized. Structures were formed by simultaneously acting major compression/thrusting, gravity sliding, and transpression/shear force fields. The shield, composed of rigid igneous and metamorphic rock, resisted deformation.

At a depth of >5 miles (overburden pressure >30,000 lb/sq in.), it deformed plastically (Fig. 5). At shallower depths, deformation was brittle and the shield eventually broke in numerous parallel, generally vertical, mainly N-S and NW-SE, and minor NE-SW and E-W striking strike-slip fault blocks.

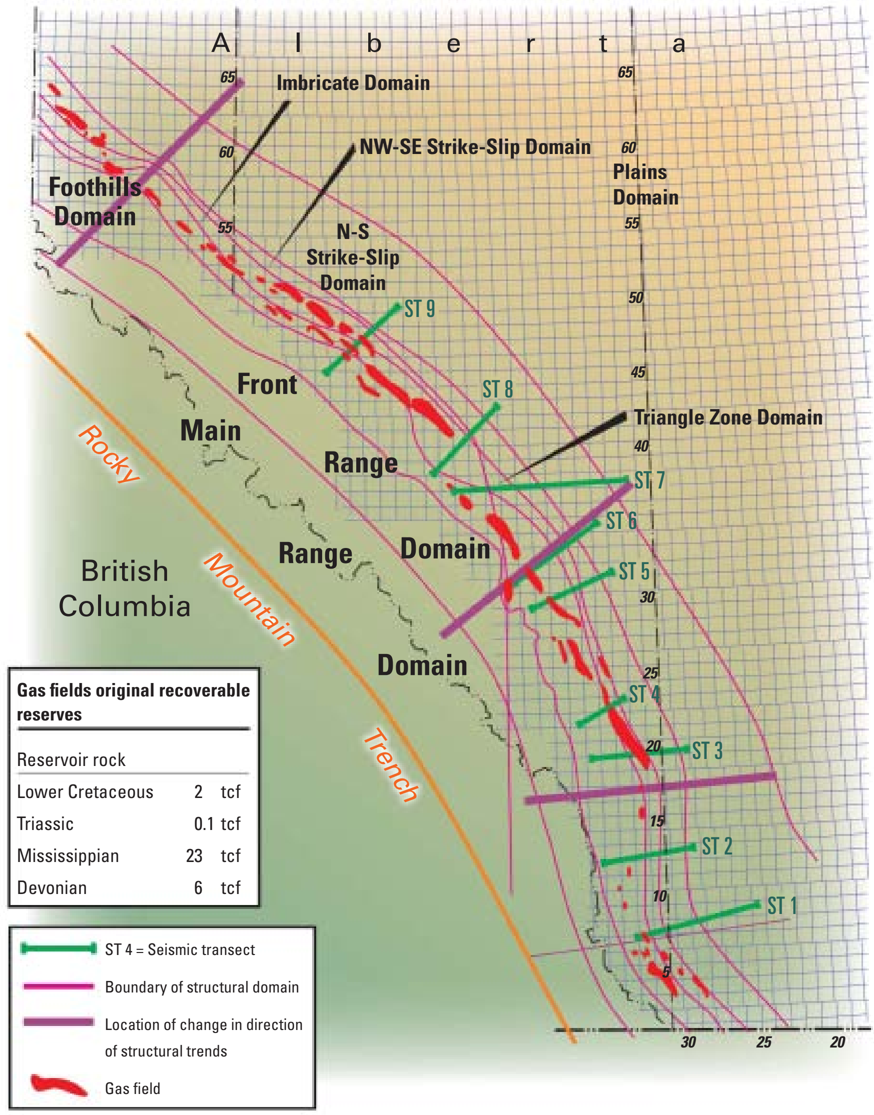
Predominant right-hand lateral movements along these faults sheared the basement many kilometers to the N and shortened it E-W. The pliable sedimentary cover, resting on this basement, sheared sideways to the NW in places along up to six subhorizontal layers separated by detachment zones.

While being deformed by shear, it simultaneously was horizontally shortened up to 100 miles by E-directed compression (thrusting and gravity sliding) in the form of enormous rock ploughs. NE and W-E shear and strike-slip zones developed within the rocks pushed by the rock ploughs.

In this dynamic setting, the section structurally thickened vertically, over large areas. While all this deformation was proceeding, sediments continued to accumulate in the WCSB, but now derived from two provenances: one in the E and a second, new one, in the W (Fig. 2).

The moving landmass formed very high topographic elevations in the W. It compound thrusted the sedimentary section to great heights, and it pushed the younger, less-compacted sections

SOUTHERN SECTION, WESTERN CANADA SEDIMENTARY BASIN Fig. 6



even higher. This facilitated eventual gravity sliding to the E.

The sedimentary section horizontally shortened (100 miles). Many thrusts in the eastern Canadian Rocky Mountains are compressional (uphill thrusts in the classical sense) in origin. Equally, many of them, especially the younger ones farther E, are gravity gliding structures. Locally, heavily imbricated and much shortened Cretaceous sections support this assertion (see seismic transect ST 6 in Part 3 of this article).

Immense continental forces are needed to push regional rock bodies uphill. Only a fraction of such force is needed to push the bodies downhill, and gravity will maintain the momentum of movement, even when the body is breaking up in numerous parallel substructures such as thrusts and imbricates.

DISCOVERED GAS IN PLACE SINCE 1913 IN WCSB STRUCTURED BELT Table 1

Age of reservoir	Alberta	British Columbia	Total
	Discovered gas-in-place in structured belt — Tcf[1]		
Lower Cretaceous	2	0.6	2.6
Triassic	0.1	6.5	6.6
Permian	0	0.5	0.5
Mississippian	23	2.5	25.5
Devonian	6	0.25	6.25
Cambrian	—	0.5	[2]0.5
Total	**31.1**	**10.35**	**41.45**

[1]As of July 1, 2005. [2]Rumored.

The structured belt

The structured belt of the WCSB includes six exploration/structural domains.

Five domains trend parallel NW. Figs. 6 and 7 are maps of the Alberta and British Columbia portions of the structured belt, respectively. From W to E, these are the Thrust Belt, Triangle Zone, Imbricate, Strike-Slip, and Plains domains. The Gravity Slide Fold Belt domain is the sixth domain.

In these domains, most structures were formed by the simultaneous interaction of several major force fields associated with compression, gravity sliding, and shear. The body of published work, although large, fails to recognize the simultaneity of compression and shear.

Some notable papers are by Gallup,[1] Bally et al.,[2] Dahlstrom,[3] Jones,[4] Price,[5] Cooper,[6] Suppe,[7] Moore,[8] McMechan and Thompson,[9] Groshong and Epard,[10] Wright, McMechan, and Potter,[11] and Mundy.[12] Noteworthy industry contributions were made by Jamieson,[13] Newson,[14] Goetz,[15] Dobson,[16-17] and Green and Granier.[18]

Pre-1900 American settlers described the region to include the "Plains" (prairie), "Foothills" (hills at the foot of the mountains), and "Rocky Mountains." These terms erroneously attained "structural geological" meanings.

Original topography of the structured belt was at least 3 miles higher than the current one. Sigma 1 and overburden pressures were much higher then than today. This is suggested by anomalously high seismic velocities (>16,500 fps) of shale sections as compared to the velocity (11,000 fps) of the same shale sections in the undisturbed Plains to the E.

The sedimentary section is in a state of "overcompaction." It has not had sufficient time to structurally relax and decompact in places, giving rise to local overpressure zones. These anomalously high seismic velocities and complex structures make seismic processing and interpretation most difficult tasks.

The regional topography once included towering mountains, which were almost leveled by four major periods of glaciations, in the past 2 million years.

The structural trend of the structured belt from S to N changes several times from NW to N and even from N to NE. These changes take place at hinge lines of unknown origin (Figs. 6 and 7).

Oil and gas

To date, only the E portion of the vast structured belt is explored.

A rewarding 41 tcf of gas in place and 1.3 billion bbl of oil in place were discovered in 169+ fields and pools since 1913 (Table 1). These discoveries followed an oil find in 1859 at Stoney Creek, NB, and gas finds at Medicine Hat, southeastern Alta., in the 1890s.

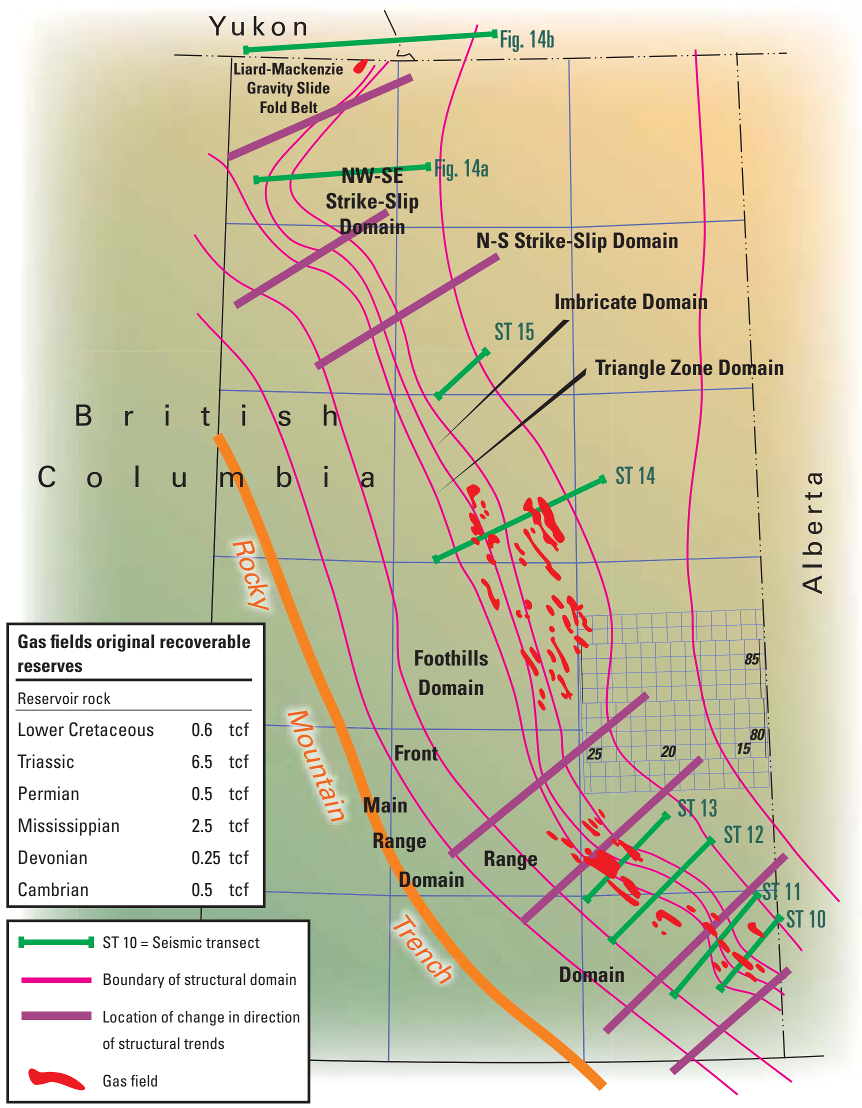
Many discovered fields include more than one structure: Sukunka field includes the discoveries of seven gas accumulations in series of shingled, independent, parallel anticlines.

Industry discovered four fields in 1910-51 (1/10 years), 47 fields in 1951-63 (4/year), went without a discovery in 1963-67, found 52 fields in 1967-81 (3.5/year), two fields in 1981-89 (1/4 years), and 20 fields in 1980-2007 (1.2/year).

Fields were discovered by Shell (12), Gulf (5), Imperial Oil (5), Phillips Petroleum (4), Suncor (4), Hudson's Bay (4), Pacific Petroleum (3), Oakwood Petroleum (3), Sun Oil (2), Sinclair (2), Czar Resources (2), BP Canada (2), Dome Petroleum (2), Devon Energy (2), and Talisman (3). More than 40 other companies discovered one pool each.

NORTHERN SECTION, WESTERN CANADA SEDIMENTARY BASIN

Fig. 7



Recently, gas discoveries (each rumored >0.5 tcf in place) were made in Permian carbonate reservoirs overlain by shale in asymmetric folds (Monkman by Talisman), in a fractured Leduc reservoir with more than 400 ft of net pay (Tay River by Shell Canada), and in Cambrian/older strata (Talisman). Clearly, this demonstrates the "Foothills" is a viable, exciting, and rewarding exploration region!

The common play is structural with stratigraphic components such as fractured carbonate, reefs, platform margins, and pinnacles. As a rule, reservoir quality is enhanced by geothermal dolomitization,[19] fracturing, and microshear faulting (Table 1).

Many discoveries will be made in the future if the oil and gas industry takes on increased risk scenarios, moves farther into the mountains, drills deeper targets, and pursues shallow resource plays.

Seismic acquisition/processing and structural geological modeling hold the key to success for the deeper targets. Completion engineering is the key for the shallower resource plays.

Drilling depths will eventually approach 7.5 km (25,000 ft), possibly deeper, at which depths high pressure-high temperature conditions (pressures >15,000 psi and temperatures >300° F.) prevail. To date, drilling depths have not exceeded 20,000 ft. The plays become costlier with deeper drilling, 3D, and 3C-3D seismic acquisition, and construction of roads, leases, tie-ins, and pipelines.

Difficulty of access and increasing distances to infrastructure add to the costs. Development of less costly shallower resource plays may be favored over expensive deep target drilling in the near future.

Despite the 2005 increase in natural gas price, drilling in the "Foothills" has not picked up as it has in other regions of the WCSB. Risk adversity, long lead times, quarterly reporting to financial markets, and dry hole and F&D costs affecting the financial "bottom line" are viewed as possible causes. Others might include inadequacy of 3D seismic acquisition and processing to properly define deeper structures. Recent downturns in gas prices will probably slow exploration in the region.

Exploration challenges

The structured belt does not easily give up its treasures.

Especially troublesome are seismic data acquisition, processing, and interpretation. Surface mapping of anticlines no longer defines drilling locations and discoveries like it did for giant Turner Valley field (1913, 1.3 billion bbl in place).

Since 1950, increasingly complex acquisition and processing methods allowed clearer and more focused images of structures in the belt. Historically, company managements rely on seismic interpretations to guide their exploration efforts. It had worked well in the undisturbed portion of the WCSB. There, seismic and geological modeling are closely linked.

Recognizing and mapping porosity are important. So, why would it not work similarly in the structured belt? And, indeed it did work well. Numerous discoveries were made guided by seismic acquisition and interpretation.


"DOT has become an important forum to visit with our clients with deepwater interests around the world. The conference in Houston was an effective way of connecting with many people in a short period of time, both on technical issues and to learn about new opportunities."
James G. Osborn, Jr. PE, Vice President Business Development / INTEC Engineering
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Oil industry management accepted a model of simplicity: "Compression from the W resulted in thrusting to the E." The reality is a tad more complex.

Currently, most shallow exploration targets (<10,000 ft), excluding resource plays, are drilled in the belt. The trend is to drill deeper targets. Unfortunately, seismic energy decreases with depth and reduces the definition of such targets. Consequently, acquisition of deep data, processing, and imaging and interpretation thereof are a challenge.

Commonly, structural geologists are not included in this process until the last minute. No wonder the end results often represent wide gaps between the real structures and those based on interpretations of iterated isotropic abstract mathematical treatises of raw seismic data.

Cases in point, deep structures with limbs that dip more than 20° are difficult or impossible to image. Thus, seismic interpretations become unrealistic to bizarre. In most cases, interpreters through recognition and mapping of impedance surfaces create geometric form (structure) maps, also called "wet blanket" maps. These maps show structural highs connected by contouring that ignores overthrusted portions of the structures.

A further problem is posed by the many active "structural" seismologists, who worked in a structured belt but had no formal structural geological training. Thus, they lack understanding of how structures are formed and what is plausible and what is not in their interpretations. Besides, not being aware of certain structural forms probably precludes mapping thereof.

Once a deep structure is identified, a structural geologist should complete mechanical and kinematic analyses of that structure. This is to determine the forces (stress) that formed the structures' geometry and the history of their development. It also aims to understand the genesis of strain (fractures) in the region.

Combined, it leads to an understanding of 3D stress and strain through time. Investigations normally should include studies of surface structures, subsurface data, including cores, well cuttings, and logs, and the review of analog structures. Unfortunately, such analyses are seldom performed as an essential part of team work leading up to budget requests and eventual drilling.

It is said, it all comes down to luck, geosteering, FMI logs (bedding and fracture dip readings) and integration with seismic data. Dipmeter interpretations work well in structured regions where deformation is not too complex and uniform. This is not the case in the subject structured belt, where structural complexity reigns: simultaneous thrusting and strike-slip faulting.

FMI logs show the presence of fractures (open, closed, and healed) with microresistivity measurements. Openings vary from a half-inch to 1 micron (about 1/2,500 in.). In laboratories, it is demonstrated that micron fractures might add 2% to 10% porosity (gas storage) to a deformed rock body. A 1/25 in. open fracture is represented by a 4-in. wide dark band on a 1:1 scale FMI log. This is a ratio of 1 to 100. This means that a 1 micron fracture should be represented by 100 x 1/25,000 in. = 1/250 in. dark band on a 1:1 scale FMI log, beyond the image resolution of that log. How wide should an open fracture be before it is visible on an FMI log?

Most evaluation engineers admit the contribution of fractures to both reservoir storage and producibility is not fully understood, especially not in not-so-obvious structural settings.

Another difficult problem faced by seismologists is that unless the rock body is entirely homogeneous from a seismic velocity point of view, it is practically impossible to mathematically precisely position a vertical well or a directional well in either 2D or 3D seismic surveys. Well synthetics might be positioned and stretched to fit the processed data, but it will always remain an inexact solution to an unsolvable problem.

Next week: How structures were formed in the structured belt, including fractures, thrusts, folds, detachment zones, and detached rock bodies, and the origin of the conventional heavy oil/oil sands belt. ✦

The author

Henri Wennekers (tamberinvestments@shaw.ca) has structural geological experience that dates from 1956 in the Alps, Pyrenees, Cantabrian Mountains, Apennines, and Bergamasque Alps in southern Europe. From 1968 onwards, with Sproule Associates Ltd. and PetroCanada, he gained further experience in the numerous northern Canadian and Greenland fold belts. He initiated, with a large team of geologists and engineers in 1976, the first regional resource analysis of 25,000 wells on 9 million acres around Lloydminster, identifying a 28 billion bbl resource base. He coordinated regional studies of Libyan basins for Sirte Oil Co. in 1988-96 and structurally mapped areas of Libya, Algeria, Chad, and Sudan. He has been a wellsite geologist and consultant since 1997. Wennekers initiated, organized, and led 19 geological field expeditions to structured regions in the past 45 years. He has a BSc, MSc, and a DrSc from State University of Leiden, Netherlands.

MPD improves drilling rates in Canadian field

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Drilling

Shell Canada drilled a well using managed pressure drilling (MPD) and an unweighted fluid system to improve drilling rate of penetration in the Bullmoose area, northeastern British Columbia.

Operators working in this area identified the Nikanassin as a very hard, slow drilling formation, which increases drilling time and costs. The Nikanassin is hard and abrasive and ranges from 1,000 m to 1,800 m thick. Elevated mud weights are sometimes required to deal with high-pressure nuisance gas or water flows, which further impedes drilling performance.

Various mud systems and bits were used in offset wells, resulting in average rates of penetration of 1.4-2.4 m/hr.

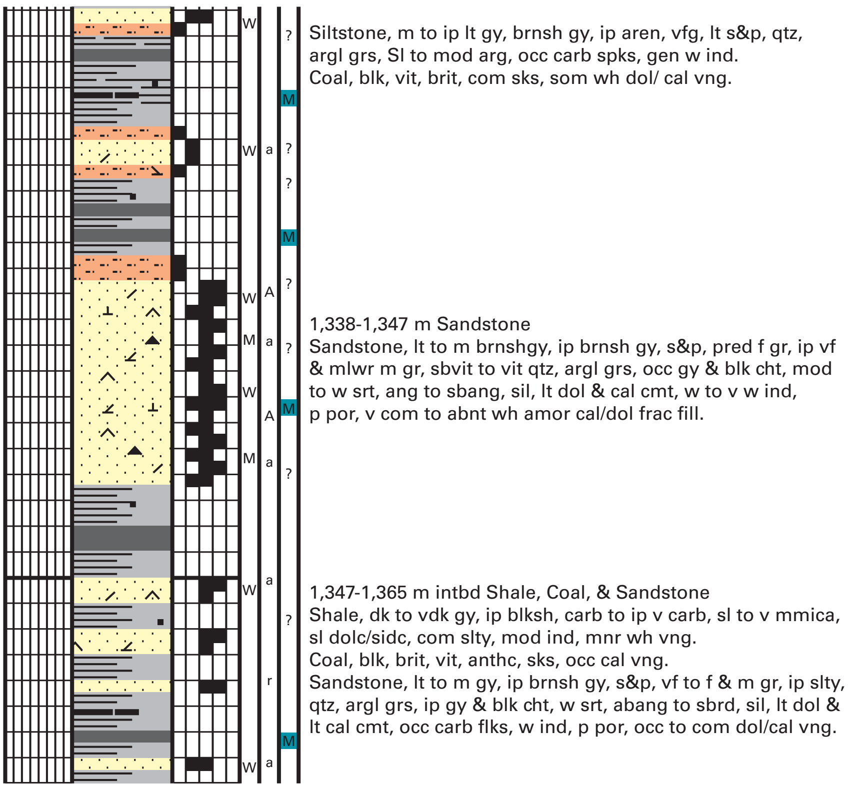
Based on a presentation to the IADC/SPE Managed Pressure Drilling and Underbalanced Operations Conference, Mar. 28-29, 2007, Galveston, Tex.

Implementing an MPD program allowed Shell to use an unweighted, flocculated water fluid system, which increased average ROP to 4.0 m/hr. When compared with low-fluid-loss mud systems, such as invert, the improvement in ROP was notable and resulted in considerable time and cost savings.

MPD is typically considered a tool to mitigate drilling hazards and reduce nonproductive time from lost-circulation zones, tight margins between pore pressure and fracture gradient, and high-pressure, low-volume, nuisance gas zones. MPD can also be used to increase ROP when air drilling and underbalanced drilling are unsuitable because of borehole instability, water flows, coal seams, or environmental concerns such as flaring gas.

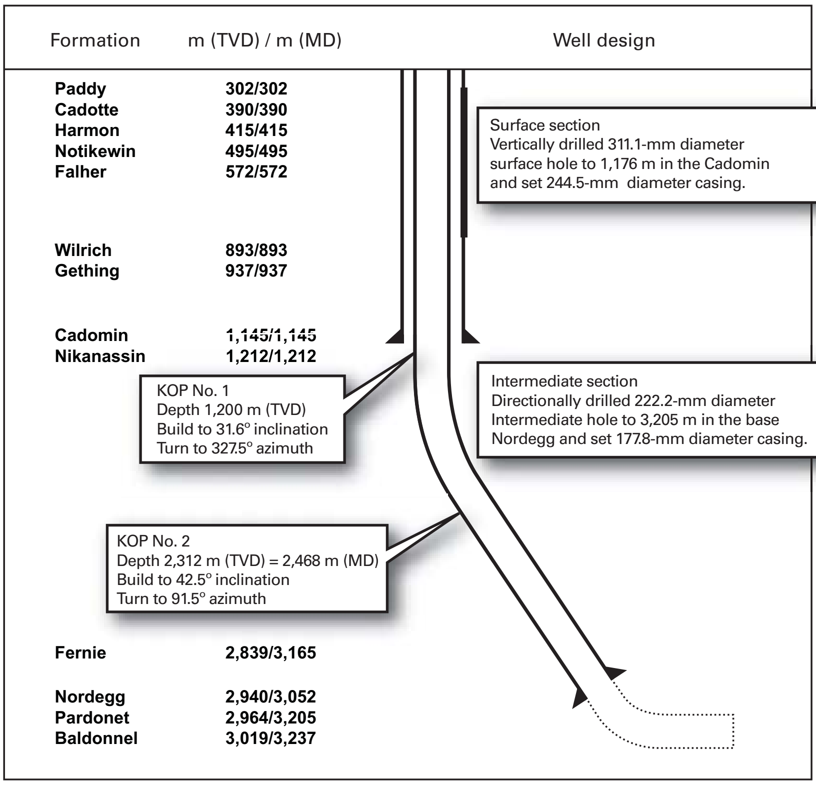
As with any advanced drilling technique, successful application of MPD technology requires a detailed understanding of the potential benefits

Geological strip log, 30-m Nikanassin section, Bullmoose field Fig. 1



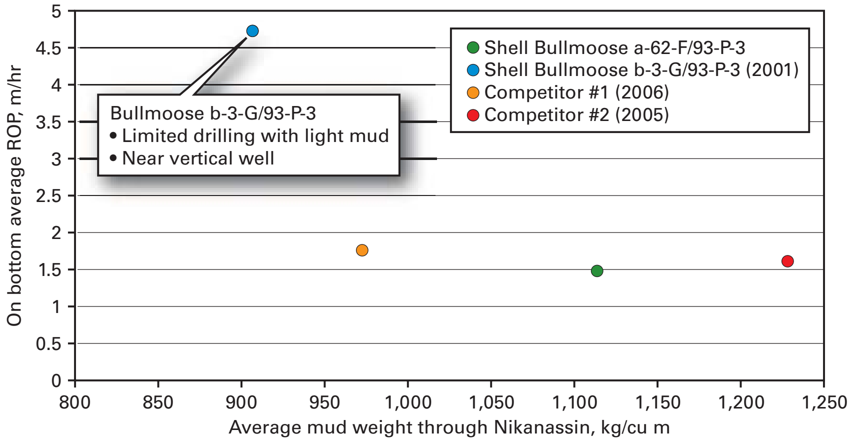
WELL SCHEMATIC, SHELL BULLMOOSE D-A80-A/93-P-3

Fig. 2



RATES OF PENETRATION, BULLMOOSE FIELD*

Fig. 3



*Results demonstrate that wells drilled with invert mud with weights above 950 kg/cu m are likely to experience ROP's below 2m/hr in the Nikanassin.

as well as limitations. This article summarizes the process that was used to identify, plan, and implement MPD as a technology to increase ROP. It discusses the lessons learned while planning and executing the MPD operation and the enhancements being considered for future use of MPD in the Bullmoose area.

Bullmoose field challenges

Bullmoose field is a highly competitive sour gas play in the 93-P-3 block, northeastern British Columbia. Since 2001, Shell Canada has participated in four exploration wells and one development well in this area. The primary hydrocarbon objectives are the Pardonet and Baldonnel formations, Triassic limestones and dolostones. To maximize production, the current well design involves drilling 500-1,500 m horizontals through these formations in order to intercept fractures and porosity.

Predominant drilling hazards include the hard and abrasive rock, steeply dipping and faulted formations, nuisance gas, water flows, and coal seams. Although each drilling risk poses its own unique challenges, the most consistent and costly problem is the hard rock encountered in the Nikanassin formation.

Drilling Nikanassin

Nikanassin is a Jurassic formation consisting of interbedded marine sandstones and shales with the occasional coal seam (Fig. 1). The sandstones consist of fine-grained quartzite and chert. The base of the Nikanassin is about 125 m (TVD) above the Pardonet and Baldonnel formations (Fig. 2).

In Bullmoose field, Nikanassin can vary from 1,000 to 1,800 m thick (TVD), and multiple tricone bits are required to drill the interval. Sand and shale sequences make bit selection difficult. A bit that will drill a sand package effectively will not necessarily perform well in the shale sections.

Also, directional drilling is often required to position the wellbore for the horizontal through the Pardonet and Baldonnel formations. Steering to align the well path properly for the horizontal section further reduces ROP, diminishes bit life, and increases the borehole length through the Nikanassin.

Finally, shallow water flows and overpressures are prevalent in Bullmoose field. The increased mud density necessary to control the inflows degrades drilling performance.

Nikanassin fluid systems

The three most common fluid systems used to drill the Nikanassin have been air, invert oil-based mud, and

NIKANASSIN DRILLING PERFORMANCE, BULLMOOSE FIELD*

Table 1

Parameter	Shell Bullmoose dA80-A/93-P-3 Water	Shell Bullmoose a-62-F/93-P-3 Invert	Competitor #1 Invert	Competitor #2 Invert	Competitor #3 Gel Chem	Competitor #4 Gel Chem
Year drilled	2006	2005	2006	2005	2004	2003
Drilled length of Nikanassin, m	1840	1,052	1,076	1,067	1,482	1,366
Number of bits required	10	14	9	12	12	12
Total on bottom drillling time, days	19	31	23	25	28	21
Average ROP through Nikanassin, m/hr	4.01	1.40	1.75	1.61	2.35	2.70
Average bit life, hr	45.9	58.8	61.9	50.7	55.8	42.2
Average bit run length, m	183.3	75.1	107	87.4	129.3	113.8
Maximum run length, m	327	160	181	191.3	316	218
Minimum run length, m	85	36	86	37	45	30
Maximum bit run ROP, m/hr	5.83	2.42	2.83	2.38	4.41	6.87
Maximum bit run ROP, m/hr	2.08	0.85	1.11	0.99	1.13	1.41

*Summarizes drilling performance through the Nikanassin of six wells in Bullmoose field, including Shell Bullmoose d-A80-A/93-P-3.

gel chemical mud.

Air drilling has been successful at increasing ROP through the Nikanassin in vertical drilling applications. Mountainous topography, however, which limits location positioning, and the requirement for horizontal well paths through the reservoir often result in deviated trajectories with borehole inclinations beyond 20o. Furthermore, aquifers within the area increase the risk of watering-out and coal seams can create hole instability. These constraints prohibit the use of air drilling in many wells.

Invert oil-based mud has been used through the Nikanassin but with limited success. Generally, invert is used not for its inhibitive properties, but rather for its low density. Offset information indicates that the density of oil-based mud must be close to 900 kg/cu m and have minimal fluid loss control before significant ROP increases are realized.

Fig. 3 demonstrates the effect of invert mud weight on ROP in the Nikanassin. In most cases, however, uphole water flows, nuisance gas, and coal gas often require fluid density to be increased, eliminating the low-density advantage of the invert mud system.

Gel chemical water-based mud is the most common fluid system in the Bullmoose area. It is a low-cost system and ROPs are slightly higher when compared with weighted, invert oil-based mud.

Planning new Bullmoose well

To minimize drilling time and cost and improve overall project economics, Shell Canada wanted to drill the Nikanassin more efficiently in the Shell Bullmoose d-A80-A/93-P-3 well.

To better understand the rock properties of the Nikanassin, Shell Canada's drilling and geological staff made a field trip to the Bullmoose area to collect Nikanassin samples. Ten rock samples were acquired from two different mapped outcrops. Geological analysis verified the composition, hardness, and abrasiveness of the rock.

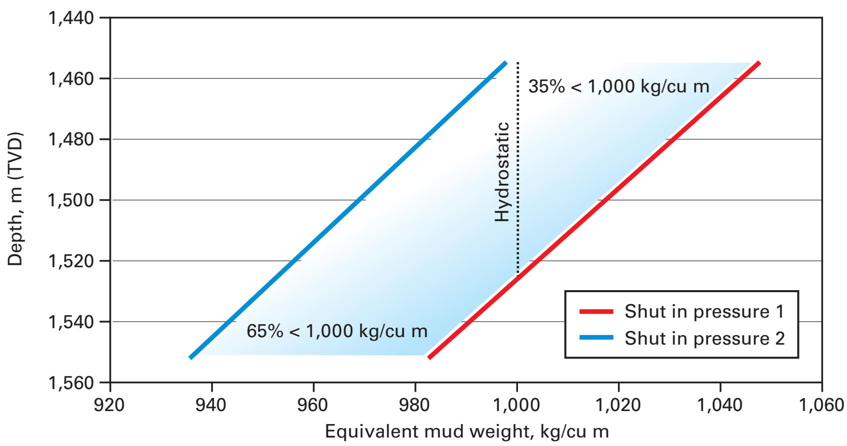
There was a lot of offset control for this project; a Kerr-McGee well was drilled in 1973, less than 100 m from Shell's proposed location. Several options were investigated, and managed pressure drilling with a flocculated water system was selected as most likely to succeed.

While drilling the Nikanassin formation, Kerr-McGee conducted a drillstem test (DST). The DST was taken from 1,455 m to 1,552 m and results indicated potential for gas flow upwards of 1.05 MMscfd. Because the DST was taken over an extended interval (97 m), an exact pore pressure gradient could not be determined. Using the two shut-in pressures recorded during the DST, operators produced a graph (Fig. 4) to estimate the pressure gradient of the Nikanassin gas.

Based on the information supplied by the DST, the expected mud weight would fall between 935 kg/cu m and 1,047 kg/cu m. This mud weight range could be achieved with an invert OBM

KERR MCGEE D-80-A/93-P-3 DST RESULTS*

Fig. 4



*Pressures converted into equivalent mud weight, kg/cu m, to determine the range of possible densities that may be required for Shell Bullmoose d-A80-A/93-P-3. The probability of requiring a mud weight greater than 1,000 kg/cu m is 35%.

mud system; however, offset data (Fig. 3) suggests that ROPs would likely range between 1.5 m/hr and 2.5 m/hr because of the low fluid loss nature of the invert and its potentially higher solids content.

The data also demonstrate that there is a 35% probability that the pore pressure could exceed 1,000 kg/cu m, which could be problematic if a fresh water fluid system were used. Although hydraulic models predict that ECDs and annular cuttings would likely increase bottomhole density to about 1,020 kg/cu while drilling with a fresh water, it is important to note that the Kerr-McGee well drilled through the Nikanassin with mud densities ranging from 1,048 kg/cu m to 1,084 kg/cu m. These mud densities could mask possible overpressures in other sections of the Nikanassin.

Offset data indicate that elevated mud weights and low ROPs can be expected if either invert or gelled mud were used to drill the 1,840-m thick Nikanassin section at the planned Bullmoose well. Therefore, a flocculated water system combined with MPD was desired because of the potential ROP benefits and pressure management capabilities. Both systems offer advantages (Fig. 5).

MPD operations planning

Considerable upfront planning was required to ensure a successful application of the technology. After a risk assessment, the equipment was selected and operations designed and reviewed to ensure meeting all of the project's key performance indicators.

Based on the risk assessment, the primary components of the MPD package were chosen. Fig. 6 shows the on site equipment. Weatherford provided an IP 1000 RCD, which has a working pressure rating of 6,900 kPa (1,000 psi), and a static pressure rating of 10,350 kPa (1,500 psi). The RCD was nippled up on a BOP with three rams (dual pipe rams, dual choke lines, and one blind ram), with annular returns directed through dual manual choke manifold

Beneficial drilling technologies

Fig. 5

Flocculated water system advantages:
- Inexpensive to mobilize and maintain compared to invert or gel chemical systems.
- High fluid loss properties result in fast pressure equalization, minimizing chip hold down effects. Data suggest that lower fluid loss muds such as invert and gels impede penetration rate in Bullmoose field.
- Low solids content could enhance ROPs.
- A high quality filter cake is not required in the Nikanassin because of the rock's hardness and relative stability.
- Swelling clays and quickly reactive shales are not known to be present in the Bullmoose Nikanassin.

MPD system advantages:
- The actual pressure regime in the offset Kerr-McGee well was unknown, and could be higher than water gradient.
- An economic analysis predicted that an average ROP of 2.6 m/hr would be required with fresh water to offset the additional costs of the MPD package. This assumes an ROP of 2.0 m/hr with an invert or gel system through the entire 1,840-m interval.
- If the overpressures are not encountered, the data can be applied to future wells in the area and the amount of MPD equipment can be minimized, or eliminated altogether.
- If the overpressures are encountered, surface hole mud can be stored and used to kill the well on trips. This would eliminate the need to trip using the rotating head, which can be time consuming.

Managed pressure drilling equipment at the Nikanassin wellsite included a Weatherford IIP 1000 rotating control device (RCD; Fig. 6)

and sample catchers. Returns were then sent to the horizontal separator.

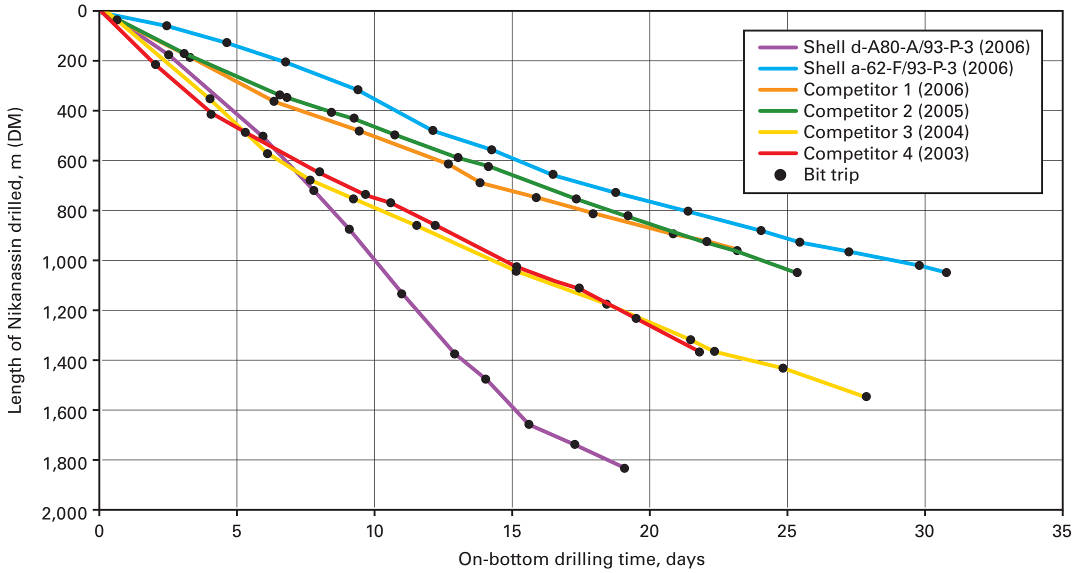
The rig choke was connected to the second inlet of the MPD choke manifold so that well control operations could be conducted through either the rig's degasser or Weatherford's separation package. From the separation package, drilling mud and solids are pumped back to the rig's shaker and mud tanks. While making connections, operators pumped fluid through the kill line, allowing for the choke operators to maintain constant backpressure on the well.

Drilling Bullmoose d-A80-A/93-P-3

Drilling with a flocculated water system and MPD resulted in significant ROP improvements compared to offset wells (Fig. 7; Table 1). A total of 10 tricone bits were used to drill the 1,840-m thick Nikanassin interval from 1,212 m to 3,052 m. At a depth of 2,834 m, the flocculated water sys-

BULLMOOSE FIELD, 6-WELL COMPARISON*

Fig. 7



*Graph compares on-bottom drilling days through the Nikanassin for recent wells in the Bullmoose field. Trip times are excluded, and each point on the graph represents a new drilling bit.

The highest volumes of gas during the operation were recorded at depths of 1,683 m (measured depth, MD) and 1,770 m MD, with flow rates of 6,000 cu m/day and 1,000 cu m/day, respectively. These rates were only observed for a few minutes before dropping back to trace amounts.

MPD operations continued with only localized hole-cleaning problems from coal seams. Other non-MPD related problems occurred, such as a motor parting and a steady increase in drill string torque and drag. The increase can be attributed to an aggressive directional profile, combined with the lack of lubricity provided by the fresh water.

Sweeps were pumped every 20 m to lubricate the drill string and to maintain the hole in good condition. At 2,834 m MD, the torque limitation of the drill string was approaching; therefore, the well was circulated over to an invert mud. The invert lubricated the drill string, improved hole cleaning, and allowed for drilling to continue.

Because invert was eventually required to drill the highly reactive Fernie shale, the economic penalty for prematurely displacing to invert was minimal.

tem was displaced with invert mud to minimize drillstring torque and drag and to improve hole cleaning. Therefore, the last two bit runs were drilled with Weatherford's MPD system and an invert oil-based fluid.

MPD operations summary

Prior to beginning MPD, crew members drilled out the casing shoe conventionally. They conducted a formation leak-off test at a depth of 1,182 m, which established the integrity at 14.9 kPa/m. Wellsite personnel held safety meetings and the crew reviewed procedures for handling, installing, and replacing the bearing section of the RCD, as well as reviewing connection procedures and other safety critical MPD procedures.

At 1,293 m depth, the bearing section of the RCD was installed and flow was diverted through the primary flow line to the separation package. As drilling progressed, high viscosity gel-mud sweeps were pumped about every 50 m and the returns were flocculated out of the water.

The first bit trip for this section was at 1,356 m. A sweep was pumped prior to removing the bearing assembly and regular flow checks were performed on the trip out to ensure the well was static. All trips were conducted in a similar fashion.

Upon running back in the hole, the drilling nipple was removed, and the RCD was installed five stands off bottom. After tripping, it was common to encounter trip gas once circulation resumed. The gas raised the pressure in the pressure tank slightly but was not significant enough to be recorded by the gas meter in the flare line.

The same situation occurred during drilling through the numerous coal seams. Once again, a slight increase in the pressure tank was observed but was quickly offset by reducing the propane volume being used to apply positive pressure to the tank.

Following a bit trip at 1,683 m, the last five stands of drill pipe were stripped in the hole. The purpose of this exercise was to familiarize the rig crew with MPD operations. During circulation across the wellhead, through the kill line and lower HCR, five stands were run in hole and the casing pressure, backpressure, and PVT were recorded after each stand.

Bit data, performance

Between two consecutive Bullmoose wells drilled by Shell Canada, the average ROP for the Nikanassin interval increased to 4.01 m/hr from 1.40 m/hr—an enhancement of 186%. Excluding trip times, the Shell Bullmoose d-A80-A/93-P-3 well took 19.1 days on bottom to drill 1,840 m of Nikanassin, whereas the previous Shell Bullmoose a-62-F/93-P-3

These photos were taken after drilling the Nikanassin section. In Fig. 8a, the bit drilled from 1,356 m to 1,683 m through the Nikanassin and was graded as 6-6-FC-A-E-3-FC-HR. In Fig. 8b, the bit drilled from 1,683 m to 1,895 m and was graded as 8-8-SD-A-F-30-CC-PR (Fig. 8).

well required 30.8 days on bottom to drill 1,052 m of Nikanassin.

Normalizing these values to days/100 m, the well drilled with flocculated water and MPD techniques required 1.05 days/100 m to drill, while the previous well required 2.93 days/100 m, a 179% improvement. Offset wells, drilled with gel-chem and invert systems required about 2.1-2.5 days/100 m. Table 1 shows bit performance for offset wells.

The second bit run in the Nikanassin set a field record, drilling 327 m in 82.75 hr, and resulting in an average ROP of 3.95 m/hr. The driller used a Hughes Christensen HR-S55 bit, which has an IADC rating of 6-3-7. When pulled, the bit's grading was 6-6-FC-A-E-3-FC-HRS.

Damage to bits was similar to previous wells drilled in Bullmoose field. Drilling through the abrasive sands often resulted in gauge wear, and gauge row inserts were usually chipped or completely worn off the bit. Figs. 8a and 8b show examples of typical bit wear through the Nikanassin.

Average bit life was also reduced compared to wells drilled with an invert or gel chemical system. The average bit life drilling with water was 45.9 hr/bit, whereas the offsets that drilled with invert oil based fluid averaged 53.6 hr/bit. This reduction in bit life is possibly due to the decreased lubricity of water.

Flocculated water performance

To flocculate the water system, a mixture of calcium nitrate, lime, and dispersible polyacrylamide (Alkapam 1103) was used. The calcium nitrate and lime provided the calcium source and the polyacrylamide flocculated the solid particles. When the fluid returned to the mud tanks after passing over the shakers, the solids would settle to the bottom of cone tanks.

Because a water system has limited viscosity, hole cleaning was done using pump rates and annular velocity. Bentonite-based gel sweeps were pumped to remove cuttings that settled out in the borehole.

The results at Bullmoose d-A80-A/93-P-3 indicate that the high fluid loss and low solids content of the water system had a significant effect on drilling rates.

After the fluid system was displaced from flocculated water to invert oil based mud, two bit runs were required to finish drilling the Nikanassin.

The average ROP of the bit runs with flocculated water was 4.51 m/hr compared to 2.12 m/hr average with the 965-990 kg/cu m invert mud. The ROPs with an invert fluid are consistent with offset well data. Clearly, mud weights were not the predominant factor that increased the ROPs.

Results

MPD operations were executed successfully on the Bullmoose well as a result of extensive prejob planning involving the operator, the MPD service provider, and the drilling contractor. The planning resulted in a job that met all the short-term key performance indicators, including drilling with increased ROP compared to the offset wells, reducing the overall well costs, and completing the MPD operation without any HSE incidents.

Compared to the previously drilled Shell Bullmoose a-62-F/93-P-3, the total time spent in the Nikanassin, including trip time, was reduced by about 24 days, and the cost was reduced by more

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than 40% for the interval.

Increased ROP on this well is primarily attributable to the use of the flocculated water drilling system. Displacing to an invert mud system for the last two bit runs of the operation resulted in the same reduced ROPs as the offset wells.

MPD was chosen based on a probabilistic analysis during the planning phase to determine the potential for encountering above-hydrostatic formation pressures. Although the expected high-pressure, low volume gas zones were not encountered, the MPD system was an enabler and was seen as a tool to manage pore pressure uncertainty.

If the high-pressure zones had been encountered, the MPD package would have been used to continue drilling while depleting any gas, allowing for drilling to continue with water.

Acknowledgment

The authors thank Shell Canada and Weatherford International for their support and permission to publish this paper. ✦

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Study evaluates how to improve rod pumping in mature field

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A study of a mature onshore field with more than 70 rod-pumped wells found several ways for improving pumping operations.

The profitability of rod pumping is a direct function of the energy requirements. For higher profits, the operator needs to maximize pumping-system efficiency. This requires finding the optimum pumping mode for the desired liquid production rate.

The study included an extensive measurement program involving more than 50% of the wells. A portable computerized system obtained the pumping parameters, and a detailed evaluation of measurement data facilitated the detection of general and specific problems in the design and operation of the pumping installations.

With the aim of improving the field-wide profitability of pumping operations, the study optimized each well's pumping parameters. Calculations showed that the operator could anticipate about a 17% field-wide power saving if all wells operate at their most economic pumping mode.

Based on a presentation to the 54th Southwestern Petroleum Short Course, Lubbock, Tex., Apr. 25-26, 2007.

Equations

$$\eta_{system} = 100\frac{P_{hydr}}{P_e} \quad (1)$$

$$\eta_{system} = \eta_{lift}\ \eta_{surf} \quad (2)$$

$$\eta_{lift} = 100\frac{P_{hydr}}{PRHP} \quad (3)$$

$$\eta_{surf} = 100\frac{PRHP}{P_e} \quad (4)$$

Nomenclature

P_{hydr} = Useful hydraulic horsepower
P_e = Electrical horsepower input to the system
η_{lift} = Lifting efficiency, %
η_{surf} = Surface efficiency, %
PRHP = Polished-rod horsepower

Study objective

The study had three different, but interrelated tasks:

1. Assess the current operating conditions of producing wells and find problems.

2. Determine the optimum pumping mode for each well while keeping current equipment and liquid production rate restrictions.

3. For selected key wells, take into account available inflow performance information to determine and verify optimum pumping system design to ensure the greatest liquid production increase by reaching pumped-off conditions.

Based on these findings, the study recommended ways to avoid problems and suggested specific ways to improve operational conditions.

The pumping mode optimization had the following restrictions:

• Liquid rates were kept at current levels.

• Main installation parameters, such as pump setting depth and tubing size, were not changed.

This evaluation allowed the operator to see the benefits of selecting the optimum pumping mode for each well. The most important improvement was the reduction of the power requirements. The study determined this for each well and for the entire field with and without tubing anchors in the wells. The current practice in the field is not to have tubing anchors.

The final study objective investigated the possibility and the effects of increased liquid production rates. This involved selecting several key wells for determining the maximum pumping rates obtainable.

For these wells, the study properly loaded and obtained sufficiently high power efficiencies for the surface systems such as pumping units and gearboxes, in contrast to current well conditions.

Measurement procedure

The study obtained measurements on the pumping wells with a portable computerized system, including the required hardware and software components, that was specifically developed for testing and analyzing sucker-rod pumped oil wells.

A complete analysis of a rod-pumped installation with the portable equipment involves several phases and requires the adherence to specific procedures. Each phase can be conducted independently but proper and complete well analysis usually has the following steps:

• Without stopping the operation of the pumping unit, find the dynamic liquid level in the annulus with an acoustic device.

• After the casing valve is closed, measure the pressure buildup vs. time at the casinghead to determine the well's gas production rate.

• Conduct a dynamometer survey to measure the polished-rod loads and movements for several pumping cycles. It is important to record a representative, stabilized surface dynamometer card for further analysis.

• Test the downhole pump traveling valve and standing valve.

• Measure the electric power used to establish the electrical parameters of the motor's input power.

Measured data evaluation

The study processed most measured data online with a portable analyzer system at the wellsite and stored appropriate parameters and diagrams in computer files. In addition to the factors calculated by the software, the study evaluated other operational parameters for each well. The following describes the parameters not readily available and those requiring additional explanation.

The study based well inflow calculations on the dynamic fluid level. After calculating the FBHP (flowing bottomhole pressure), the study had two options available for finding the well's inflow performance:

1. Use the constant PI (productivity index) principle.
2. Use the Vogel IPR (inflow performance relationship) curve.

For the majority of the cases, the study used the PI principle because no free gas entered the wells from the perforations.

Other parameters included:

• Surface system loadings expressed as percentages of equipment ratings.

• Beam loading calculated as the ratio of the measured PPRL (peak polished-rod load) to the pumping unit's structural load rating.

• Gearbox loading determined from the ratio of the measured peak net torque and the torque capacity of the gearbox.

• Motor load expressed by the ratio of the rms (root mean square) current taken by the electric motor to the motor's full-load current rating.

• Rod loading of the individual tapered portions of the string expressed as the percentage of the maximum allowed rod stress. The allowed stresses were calculated from the modified Goodman diagram, which is used for evaluating the fatigue loading of sucker-rod strings.

PUMPING MODE OPTIMIZATION OF SELECTED WELLS

Table 1

Well	A	B	C	D	E
Present pumping mode					
Plunger size, in.	2.5	2.5	2	2.5	2.25
Stroke length, in.	124	88	106	124	88
Pumping speed, spm	9.5	9.5	9	9	10
Optimum pumping mode, without tubing anchor					
Plunger size, in.	2.75	2.75	2.75	2.75	2.75
Stroke length, in.	124	88	88	124	88
Pumping speed, spm	7.7	7.1	6.2	7	6.8
Rod string					
API Rod No.	87	86	86	87	86
Top taper, %	28.8	26.4	25.3	29.7	25.7
Middle taper, %	72.8	25.2	22.1	72.3	23.1
Bottom taper, %		50.0	55.9		53.7
Optimum pumping mode, with tubing anchor					
Plunger size, in.	2.75	2.75	2.75	2.75	2.75
Stroke sength, in.	124	88	88	106	88
Pumping speed, spm	7.6	7	6.1	8.2	6.7
Rod string					
API Rod No.	87	86	86	87	86
Top taper, %	28.8	26.4	25.3	29.7	25.7
Middle taper, %	71.2	27.1	26.3	70.3	26.1
Bottom taper, %		46.5	48.4		48.2
Improvements					
Unanchored tubing string					
Relative lifting efficiency increase, %	19.0	12.5	75.0	13.3	42.1
Relative energy saving, %	16.0	11.1	42.9	11.7	29.6
Anchored tubing string					
Relative lifting efficiency increase, %	20.2	14.9	80.0	16.8	42.1
Relative energy saving, %	16.8	13.0	44.4	14.4	29.6

The analysis program calculates the degree of counterbalancing of the gearbox and recommends ways for achieving optimum conditions. This may involve moving or replacing counterweights on the unit's cranks.

The results of the valve tests as well as the shape and other parameters of the calculated pump cards determined the downhole pump conditions. In some cases, usually for wells with older production tests, the calculated pump displacement varied substantially from the latest measured liquid rate. In such cases, to verify the measurement accuracy, the study calculated the pumping rate with the API RP11L model.[1]

If the calculated liquid rate did not agree with the analysis program output, the study did not use the production test data and recommended a new test.

Various publications define and calculate power efficiency of sucker-rod pumped installations in different ways.[2-4] This study defines power efficiency, in general, as the ratio of useful and total input power to a system.

The useful power for the rod-pumping system is calculated from the amount of liquid lifted and the lifting depth, while the total electrical energy input to the system is measured with the portable analyzer. Thus, Equation 1 (see equation box) yields total system efficiency.

The system's total efficiency equals the efficiencies of the downhole system added to the efficiency of the surface drive train. The latter includes the pumping unit, gearbox, V-belt drive, and electric motor. With the efficiencies to those two components assigned, Equation 2 will express the system efficiency. Lifting efficiency represents the efficiency of energy used and the losses in the downhole system, which includes the downhole pump and the rod string. Its value depends on the proper selection by the production engineer of the pumping mode, which includes pump size, polished-rod stroke length, and pumping speed.

Equation 3 calculates the lifting efficiency from the measured polished-rod power (PRHP).

The surface efficiency, calculated with Equation 4, includes all energy losses in the drive train.

A comparison of the efficiencies facilitates the detection of problems in a given rod-pumped installation.

The accompanying box shows the main results from the evaluation of the wells in the mature field.

Artificial design

Artificial lift design aims to ensure the most economic means of liquid production within the constraints imposed for the given well and reservoir. For rod pumping, this means selecting the right size of pumping unit and gear reducer, as well as determining the pumping mode.

A designer only can select the pumping unit and gear reducer size if the operating conditions, such as loads and torques, are known. These conditions vary for different pumping modes. The basic task of a proper design, therefore, lies in determining the optimal pumping mode.

Optimum pumping mode is the combination of pump size, polished-rod stroke length, pumping speed, and rod-string design that results in the maximum lifting efficiency (Equation 3).[6 7] This coincides with the case of setting the polished rod horsepower (PRHP) to a minimum because lifting efficiency and PRHP are inversely proportional for lifting a given liquid volume from a given pump setting depth.

The pumping mode determined with the previously described principle needs the least amount of prime-mover power because the system's total energy requirement is a direct function of PRHP. Application of this optimization concept, therefore, gives the most energy-efficient and thus most economic pumping mode for producing the desired liquid rate from the given pump setting depth.

As also shown by Gault,[8] a pumping system design using this principle results in minimum operational costs and in maximum system efficiency.

In rod pumping, power costs for driving the prime mover are a large part of operating costs. Thus the importance of selecting the proper pumping mode that meets minimum energy requirements cannot be overestimated.

The optimization procedure, as discussed, finds the least amount of power required at the polished rod. Because total energy use of the pumping system is directly related to polished-rod horsepower (PRHP), the optimization model automatically finds the most energy-efficient pumping system.

Optimization strategy

The study optimization evaluation included the following restrictions:

- Maintain liquid production rates as reported in the latest production tests, if reliable.
- Use present surface equipment such as pumping unit and prime mover.
- Use the current rod-string composition (API Rod Code).
- Do not change pump setting depths.
- Use dynamic fluid levels as measured.
- Use water cut from the latest production test.

The two cases studied included one with and one without a tubing anchor in the wells. The optimization process involved not only the optimum pumping mode parameters but also required the design of the rod string.

Calculated results

Table 1 shows the results of the pumping mode optimization for some of the wells investigated. The table lists the optimum pumping modes along with the required rod-string designs. It also includes for each well the following parameters related to the power efficiency of the pumping system:

- Increase in lifting efficiency, related to the current value.
- Decrease of energy requirements related to the current energy consumption.

The average energy savings per well for the 30 valid cases in this study is 16.4% for unanchored and 18.3% for anchored tubing strings. The operator can expect a field-wide power saving of about 17% if all wells are converted to their most economic pumping modes.

Optimizing key wells

The study also investigated the potential for increasing the liquid production rates of several key wells in which the higher rate was expected to have a limited effect on the well's water cut.

This optimization involved determination of the maximum possible liquid rates as well as the selection of the optimum pumping modes that would ensure those rates. All predictions used the following assumptions:

- Because wells already have the largest possible tubing size for the casing sizes, tubing size was not included in the optimization.

Well evaluations

The main results of the well evaluation were as follows:

1. Table 1 shows the counterbalancing of gear reducers for the wells investigated. More than half of the investigated wells cannot be properly balanced because of very light pumping loads. The units are weight heavy even without counterweights on the cranks.

COUNTERBALANCING

Table 1

Counter-balancing condition	No. of wells	% of wells
Perfectly balanced	3	8.8
Not perfectly balanced, but correctable	13	38.2
Impossible to balance	18	53.0
Total	**34**	**100.0**

2. Stuffing boxes require regular checking for leaks and tightness. Too loose boxes result in fluid leaks, whereas overtightened stuffing boxes increase well loads and may cause downhole problems.

STUFFING BOXES

Table 2

Stuffing box condition	No. of wells
Slightly overtightened	4
Excessively overtightened	6

• Existing pumping units on the wells were used in the optimization.

Calculation procedure

Rod-pumped wells produce at a maximum liquid production when the subsurface pump operates near to a pumped-off condition. This condition means that the dynamic liquid level should be at the pump's setting depth.

It follows that the rod-pumping system has its maximum liquid production capacity when the pump is set at a depth just above the well's perforations. The study, therefore, recommends setting the pump depths for the key wells at a few hundred feet above the perforations.

The first step in optimizing the key wells determined the maximum possible liquid rate, q_{lmax}, from the well using the PI and the calculated FBHP.

Assuming the existing pumping unit with its capacity restrictions, the next step calculated the maximum liquid production capacity, q^*_{max}, of the pumping installation. When determining this rate, it considered the following parameters:

• A pump size compatible with the well's tubing size.

• Availability of polished-rod stroke lengths and pumping speeds on the given pumping unit.

• Pumped-off well conditions.

The optimization process considered all possible combinations of these parameters and designed rod strings for each individual case. The results only kept the cases meeting the following criteria:

• Rod strings not overloaded, considering the fatigue endurance limits of Grade D rods.

• Gearbox not loaded above the torque rating of the given pumping unit.

• Peak polished-rod load (PPRL) less

Table 2 shows the condition of the stuffing boxes on the wells surveyed.

3. The operation of the standing and traveling valves greatly influences the downhole pump conditions. The valves should be checked frequently for proper operation and the amount of wear. Table 3 lists the valve conditions, based on field measurements

Downhole valves

Table 3

	No. of wells	% of wells
Standing valve condition		
Holds perfectly	32	97.0
Leaking	1	3.0
Total	**33**	**100.0**
Traveling valve and barrel conditions		
Perfect	13	40.6
Leaking less than 5 b/d	11	34.4
Leaking more than 5 b/d	8	25.0
Total	**32**	**100.0**

4. Lifting efficiency, as defined in Equation 3, represents the amount of downhole losses in a sucker-rod pumped well. For any well producing a specific liquid rate, it can be changed in a broad range by modifying the pumping mode while the well's rate is unchanged.

For properly designed pumping installations, lifting efficiencies range between 70 and 85%.[5] Table 4 shows the lifting capacity determined from the survey.

Lifting efficiencies in more than half of the investigated wells are below 75%, meaning that current pumping modes (plunger sizes, stroke lengths, and pumping speeds) are not optimum.

Lift efficiency

Table 4

Lifting efficiency ranges	No. of wells	% of wells
Less than 25%	1	4.0
25-50%	7	28.0
50-75%	6	24.0
More than 75%	11	44.0
Total	**25**	**100.0**

5. Measurements showed that the rod strings were strong enough and had sufficiently uniform fatigue loading, although they were excessively overdesigned and are therefore too heavy. Table 5 lists the average fatigue loadings of the rod strings.

Rod string loading

Table 5

Average rod string loading	No. of wells	% of wells
Acceptable (more than 60%)	3	9.0
Light (between 60% and 40%)	21	63.6
Very light (less than 40%)	9	27.4
Total	**33**	**100**

6. Surface efficiency of sucker-rod pumping components, if they are properly loaded, is usually very high. Average efficiencies are 90% for a pumping unit and 80% for the gearbox.[5,6]

The total surface system efficiency, therefore, lies between 60% and 75%, provided the pumping unit and the gearbox have proper loading.

Surface efficiency

Table 6

Calculated surface efficiency	No. of wells	% of wells
Optimum, more than 70%	—	—
High, between 60% and 70%	—	—
Low, between 40% and 60%	20	77.0
Very low, less than 40%	6	23.0
Total	**26**	**100.0**

Efficiencies calculated from measured data, Table 6, verify that practically all pumping units are extremely oversized for the job.

Optimization for selected key wells

Table 2

Well	Key-1	Key-2	Key-3	Key-4	Key-5	Key-6	Key-7
Well data							
Tubing size, in.	2.875	2.875	3.5	3.5	2.875	3.5	3.5
Pump setting depth, ft	4,700	4,600	4,900	4,200	4,800	4,800	4,400
Inflow data							
Shut-in bottomhole pressure, psi	1,749	1,749	1,820	1,350	1,749	1,749	1,350
PI, b/d/psi	0.47	0.65	0.96	5.80	0.91	0.67	3.70
q_{lmax}, b/d	755	1,000	1,620	6,670	1,457	1,057	4,536
System capacity calculations							
Plunger size, in.	2.25	2.25	2.25	2.5	2.25	2	2.5
Stroke, ft	144	144	124	106	124	144	106
Pumping speed, spm	12	12	12	12	12	12	12
q^*_{max}, b/d	910	922	770	783	767	741	777
Optimum pumping mode							
Plunger size, in.	2.25	2.25	2.25	2.5	2.25	2	2.5
Stroke length, in.	144	144	124	106	124	144	106
Pumping speed, spm	10	12	12	12	12	12	12
q_{opt}, b/d	755	922	770	783	767	741	777
PRHP	34.2	40.5	33.6	28.9	34.1	37.4	28.9
Lifting efficiency, %	72.1	75.4	77.0	78.1	76.0	65.5	79.7
Rod string							
API Rod No.	86	86	86	86	86	86	86
Top taper, %	35.8	33.2	34.9	39.0	35.4	31.3	38.9
Middle taper, %	34.2	32.6	33.6	37.4	34.0	30.8	37.4
Bottom taper, %	30.0	34.2	31.6	23.6	30.6	37.9	23.6
Loadings							
Beam loading, %	65.2	65.0	66.2	89.6	66.2	62.7	92.0
Gearbox loading, %	85.0	88.7	75.9	88.2	76.5	83.5	89.3
Top rod loading, %	89.6	97.1	96.7	92.6	97.2	92.8	95.5

than the pumping unit's polished-rod capacity.

At this point, the optimization process compared the two liquid rates q_{lmax}, the well's capacity, and q^*_{max}, the pump installation's capacity and, obviously, selected the smaller of the two for all subsequent optimization calculations.

The next step in the process determined the optimum pumping mode to obtain the desired production rate. This involved selection of pump size, polished-rod stroke length, and pumping speed combination that ensured maximum lifting efficiency. As in the previous calculation, this calculation assumes a perfectly balanced pumping unit.

Optimization results

For some sample wells, Table 2 shows basic well data, results of the inflow calculations, and system capacity calculations. It also lists parameters of the optimum pumping mode along with detailed design of rod string and loadings of main system components.

This study provided the following conclusions.

- Practically all of the determined optimum pumping modes have lifting efficiencies in the 70% to 85% range.
- The fatigue loading of the top tapers in the rod strings is sufficiently high to ensure proper utilization of the rod's strength.
- All of the beam loads, compared to the unit's polished-rod capacity, are greater than 60%, an indication of a proper design.
- Gearboxes are loaded fully to ensure a high torque efficiency of the pumping unit.

It must be emphasized that, contrary to current operating conditions, the sucker-rod pumping installations designed for the key wells are loaded properly.

Because of proper loading of gearbox and pumping unit, one can expect surface system efficiencies in the optimum range between 60% and 75%. By comparison, all wells included in the field measurement phase of this project fell below the 60% efficiency range. ✦

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Saudi Aramco installs new LPG recovery unit at Yanbú refinery

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Refining

Saudi Aramco recently converted its semi-regenerative platformer unit in its Yanbú refinery to a UOP-licensed continuous catalytic regenerative (CCR) process. To recover valuable gases from the CCR net gas, Saudi Aramco installed an LPG-recovery unit that uses a technology unfamiliar to the refiner.

The new unit (Fig. 1) was installed to maximize LPG recovery and increase hydrogen purity of the net gas for use in a new diesel hydrotreater unit.

This article describes how the enhanced absorption process was incorporated at the Yanbú refinery to complement the existing saturate-gas-conditioning unit and shares the experience with the start-up and operations of the LPG-recovery unit.

The recovered, higher-value LPG is separated in an existing debutanizer column. A new three-stage propane refrigeration system is used to chill the CCR net gas to maximize LPG recovery.

Yanbú reformer

The original fixed-bed platformer unit had operated in the Yanbú refinery since 1983. Saudi Aramco elected to revamp the 38,000-b/d UOP fixed-bed

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platformer into a 40,000-b/d CCR platformer system to:

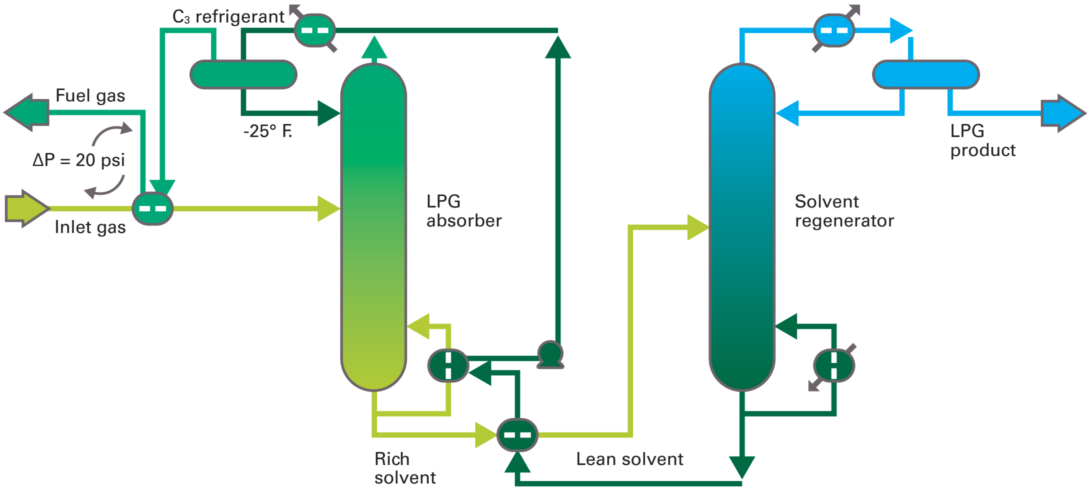
- Increase unleaded gasoline production by 8,000 b/d.
- Increase refinery-product values by allowing the option of blending light straight-run naphtha and butanes into the gasoline pool.
- Reduce requirements for expensive methyl tertiary butyl ether purchases.
- Improve reliability, safety, and efficiency by reducing unit downtime.

As part of the reforming process, the CCR system produces a net gas that is rich in C_{3+} LPG and hydrogen. To maximize propane recovery from excess net gas and existing saturated gas debutanizer overhead, Saudi Aramco chose a licensed LPG-recovery system from Advanced Extraction Technologies Inc. (AET) because of its effectiveness in achieving high propane recoveries (96+%) from about 151 psig offgases without requiring feed-gas compression.

This article describes the incorporation of new-to-Saudi Aramco technology and shares the experiences with the AET LPG-recovery unit that started up during June-July 2006.

AET LPG RECOVERY UNIT

Fig. 2



LPG-recovery technology

A typical AET LPG-recovery unit (Fig. 2) uses a C_{5+} solvent for absorbing the C_{3+} LPG components from a refinery offgas stream. C_{5+} solvent is used because it has low molecular weight, which reduces solvent circulation, and a low vapor pressure, which reduces solvent loss.

In the AET process, absorption effectiveness is further enhanced when the lean C_{5+} solvent is presaturated with the "undesired" hydrogen and methane in the inlet refinery offgas (fuel gas). This is available at the LPG absorber overhead because the propane and butanes are removed from the offgas inlet gas in the absorber column.

The presaturated solvent at about 25° F., separated from the fuel gas, is pumped to the top of the absorber. This hydrogen-methane presaturated solvent, upon entering the absorber, absorbs only the propane and butanes.

The LPG absorber is reboiled to ensure that recovered C_{3+} LPG meets the specification content for all light ends in the inlet refinery offgas. Rich solvent from the LPG absorber bottom is fractionated in the solvent regenerator to separate absorbed C_3-C_4 LPG as an overhead product and a C_{5+} lean solvent as the bottoms. The solvent regenerator operation is similar to that of a debutanizer column. Any new AET process facility therefore requires an LPG absorber column and a debutanizer-regenerator column.

LPG recovery at Yanbú

Because the refinery already had a debutanizer column as part of its saturated gas concentration unit, Saudi Aramco considered alternatives to eliminate the need for a new debutanizer column just for the new LPG absorber.

Instead of securing a new segregated C_{5+} stream as the lean solvent, Saudi Aramco considered stabilized platformate, which is a C_{5+} product available from the existing debutanizer column, as the preferred lean solvent. Unfortunately, the required solvent circulation rate of stabilized platformate as lean solvent was large enough to require a larger-diameter debutanizer column.

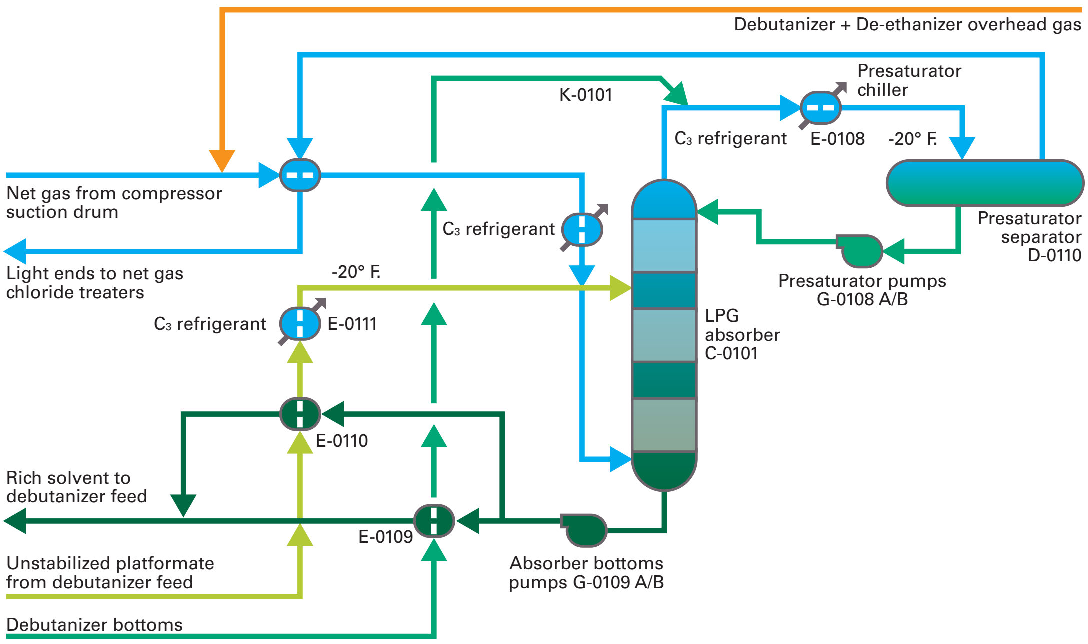
In order to use the existing debutanizer column, some of the unstabilized platformate feed to the debutanizer was redirected to the new LPG absorber to absorb some of the LPG from the CCR net gases.

Circulating some of the stabilized platformate from the bottom of the existing debutanizer as lean solvent for the LPG unit absorbed the remaining LPG in the CCR gases. This essentially

In this photo of the new LPG-recovery unit, the absorber column is in the center and on top of the nearby pipe rack is the propane-refrigerant condenser. The two columns in the lower right-hand side are the existing saturated gas plant debutanizer (on the left) and depropanizer (on the right with the red flag). The debutanizer column fractionates the LPG absorber bottoms and sends a part of its bottoms to the top of the LPG absorber as the lean solvent (Fig. 1).

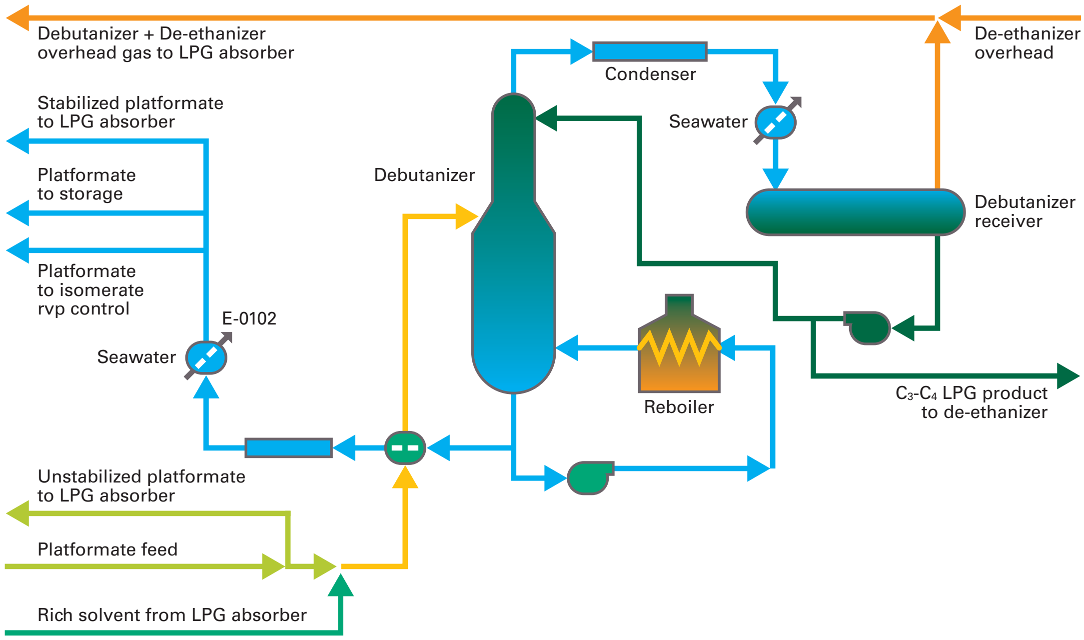
LPG ABSORBER CONFIGURATION

Fig. 3



MODIFIED DEBUTANIZER CONFIGURATION

Fig. 4



split the total C_{5+} solvent requirement for the desired high-propane recovery. We solved the problem of using unstabilized platformate feed, which is essentially saturated with propane and butanes, as a bulk solvent for part of LPG absorption by chilling the unstabilized platformate to a significantly lower temperature of 20° F.

Fig. 3 shows the LPG absorber configuration.

To minimize platformate loss from the absorber overhead and to increase LPG absorption efficiency, the stabilized platformate solvent stream is presaturated with hydrogen, methane, and ethane. It is mixed with overhead gases from the LPG absorber and chilled to about –20° F. Chilled gases are separated from the chilled solvent stream in a pre-saturation separator. The presaturated lean solvent is pumped to the top of the LPG absorber column.

Unstabilized (bulk solvent) and stabilized debutanizer bottoms (lean solvent) platformate streams are precooled with a cold stream from the absorber bottoms stream and then chilled with propane refrigerant to –20° F. CCR net gas combines with the recycled overhead gases from the debutanizer and de-ethanizer to form the combined feed to the LPG absorber.

The combined gas stream is precooled with cold energy from propane free, light-end gases and then chilled to 20° F. before entering the LPG absorber near the bottom.

The upward-flowing chilled gases counter-currently contact the downward-flowing presaturated lean solvent, which absorbs C_{3+} components. Cold, rich solvent from the LPG absorber bottom is pumped and warmed against the unstabilized and stabilized platformate solvent streams. It

then joins the unstabilized platformate feed stream to the existing debutanizer downstream of the take-off point for the unstabilized solvent.

Comparing Figs. 2 and 3 shows that the LPG absorber at Yanbú does not have a reboiler. The simpler absorber design takes advantage of a de-ethanizer in the saturated gas concentration unit, which takes feed from the debutanizer overhead to meet the ethane specification of the C_3-C_4 product.

Fig. 4 shows that, at the debutanizer overhead, uncondensed light-ends are separated from the condensable C_3-C_4 mixture. Overhead liquid C_3-C_4 product is further fractionated in a de-ethanizer and depropanizer, which produce C_3 and mixed C_4 products.

Separated light ends from the debutanizer overhead, along with the separated ethane and lighter from the overhead of de-ethanizer, are recycled back to the LPG absorber to recover any C_{3+} hydrocarbons.

Overall material performance — Table 1

Component	Combined gases from CCR and saturated gas plant: Flow, 1,000 mole/hr	Combined gases: Components, mole %	Product gas to diesel hydrotreater and fuel gas: Flow, 1,000 mole/hr	Product gas: Components, mole %	Yields — Gas products: Recovery, %	Yields — Gas products: Flow, cu m/hr
Hydrogen	2,170.20	73.62	2,168.31	88.63	99.9	48,601
Methane	107.15	3.63	104.21	4.26	Liquids products	
Ethane	245.38	8.32	165.84	6.78	Recovery, %	Flow, b/d
Propane	239.75	8.13	3.37	0.14	98.6	3,277
Isobutane	52.04	1.77	0.22	0.01	99.6	853
n-Butane	62.29	2.11	0.79	0.03	98.7	951
Isopentane	22.91	0.78	2.29	0.09	90.0	380
n-Pentane	12.62	0.43	0.70	0.03	94.5	217
C_{6+}	35.41	1.20	0.64	0.03	98.2	719
Total	**2,947.75**	**100.00**	**2,446.37**	**100.00**		**6,398**
Flow, cu m/hr	69,700		57,845			

Propane compressor start-up trips — Table 2

Trip	Trip type or symptom	Lesson learned or follow-up action taken
1	High vibration	Bypass trip setting during initial start-up.
2	High amperage load	Watch amperage indication to prevent overloading the compressor motor.
3	High-high level, first-stage suction drum	Fix and calibrate level transmitters and flow transmitters for accurate display on DCS screen.
4	High discharge temperature	1. Bypass current trip setting of 95° C. and watch discharge temperature to not exceed vendor recommended limit of about 150° C. 2. Change start-up procedure to introduce chiller vapors into the compressor as quickly as possible.
5	Loss of level indication in suction drums and trip from high-high level	Refill with glycol and place plugs to prevent loss of fluid in level transmitter legs.
6	Loss of suction pressure	Do not start compressor with isolation valves open on discharge and three suction stages.
7	High discharge pressure from cascading discharge temperature with discharge pressure	Avoid cascading discharge pressure and temperature until unit is stabilized and close in desired settings and the cascading configuration is checked and fixed.
8	Low suction pressure	Avoid imbalance from opening 5% of suction pressure valve when compared to opening 30% discharge pressure valve. Increase suction and discharge openings in equal increments.
9	Amperage overload from low-pressure economizer pressure valve opening to 33% from 5%	Avoid rapid opening of low-pressure and high-pressure economizer pressure valves.
10	Third-stage suction drum high-high level	Unreliable level transmitter operation. Avoid compressor operation until level indication is reliably displayed on DCS screen.
11	First-stage suction high-high level due to stuck first-stage antisurge valve and loss of suction pressure trip	1. Check, fix, and recalibrate the first-stage antisurge valve and assure its operation. 2. Do not open drain valve too quickly. 3. Assure flow from 2-in. hot sparger gas line in suction drums to assure imbalanced quench liquid is vaporized.
12	1. Third-stage antisurge valve stuck Third-stage suction high-high level 2. First stage antisurge valve stayed open throughout	1. Fix solenoid and recalibrate the third-stage antisurge valve functionality. 2. Recognize that the antisurge valves will remain open at inlet gas flow from CCR less than 88% of design flow to the LPG recovery unit.

To handle increased processing load in the existing debutanizer, modifications to existing equipment included:

- Addition of series heat-transfer surface to the feed-bottoms exchanger.
- Addition of parallel heat-transfer surface to the bottoms product seawater cooler.
- Addition of a new overhead seawater trim condenser.
- Replacement of overhead product and reflux pump.

Feed pumps were replaced in the existing de-ethanizer system. In the depropanizer system, the overhead air-cooled condenser was replaced with a seawater shell-and-tube condenser and the overhead net propane product cooler was replaced with a larger heat exchanger.

Propane refrigeration cycle

To provide the required chilling, a propane refrigeration system was required.

Fig. 5 shows the closed loop, three-stage propane refrigeration cycle, which provided the necessary chilling for the unstabilized and stabilized platformate solvent streams and CCR net gas feed to the LPG absorber.

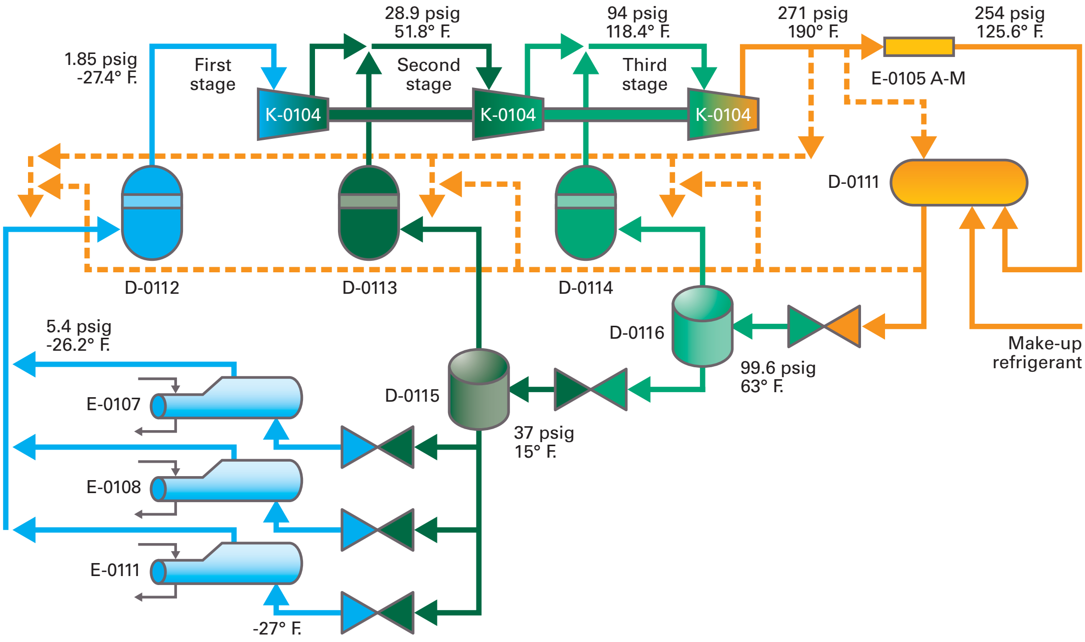
All of the three process services—the feed gas chiller E-0107, platformate chiller E-0111, and presaturation chiller E-0108—cool the respective process streams to about 20° F. using 27° F. propane refrigerant. Vaporized propane from the chillers enters propane compressor K-0104 through the first-stage suction drum D-0112.

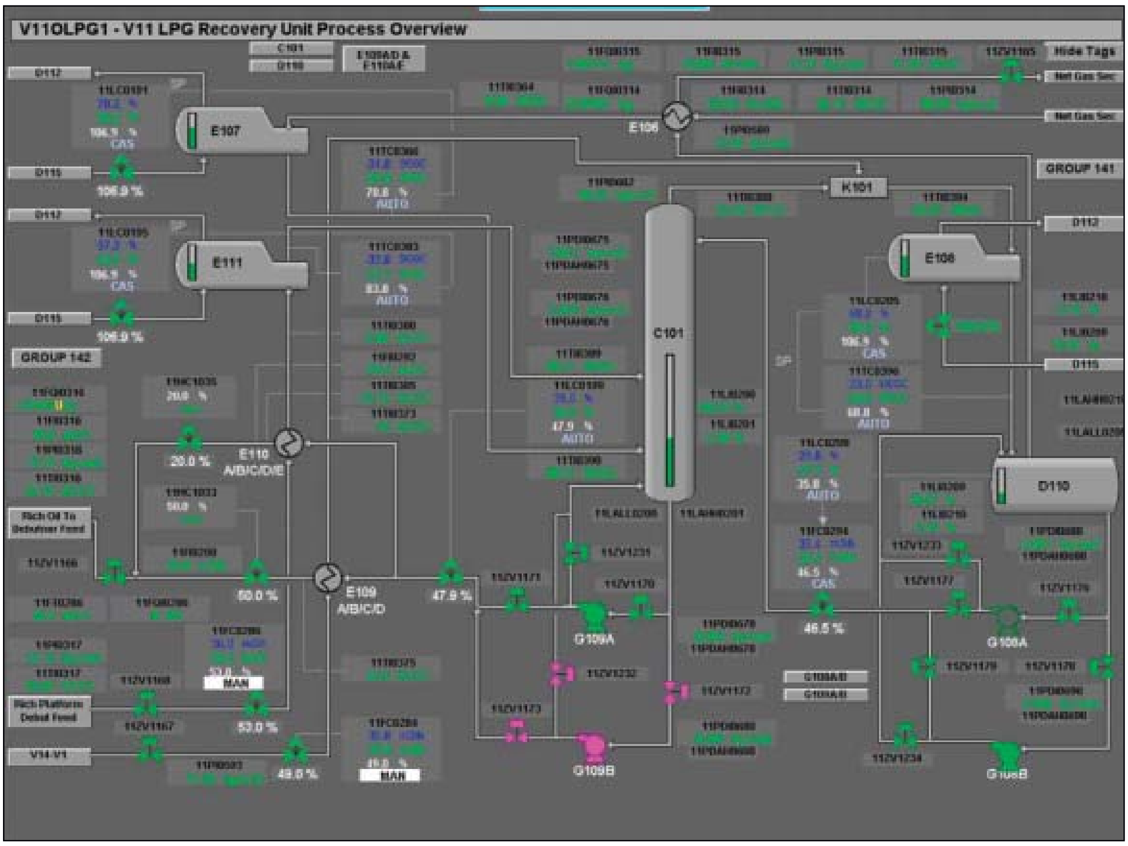
The low-pressure economizer D-0115 and high-pressure economizer D-0116 reduce the refrigerant compressor horsepower by separating the second-stage side load flashed vapors at 15° F. and third-stage side load flashed vapors at 63° F., respectively. Compressed propane refrigerant vapors are condensed in the air-cooled condenser E-0105 and returned to the propane accumulator D-0111.

The dotted line in Fig. 5 shows that

PROPANE REFRIGERATION SYSTEM

Fig. 5





Here is the DCS system screen for the LPG-recovery unit overview after start-up of the refrigeration system (Fig. 6).

the refrigerant compressor's antisurge system controls the flow of hot discharge propane and quench liquid propane to the first, second, and third-stage suction drums, D-0112, D-0113, and D-0114, respectively.

Overall design performance

Because the LPG absorber was integrated with the debutanizer, de-ethanizer, and depropanizer in the saturated gas concentration unit, it is quite cumbersome to ascertain the material recovery performance of the LPG absorber system. By drawing an envelope around the integrated system, we determined LPG recovery by analyzing the two gas streams (Table 1).

Precommissioning activities

The unit was constructed as part of a platformer revamp project. When the mechanical construction was completed, Saudi Aramco had performed these precommissioning activities:

- 120 hydrotests were done.
- 280 instrumentation loops were checked.
- Eight refrigeration loops were chemically cleaned.
- Propane compressor lube oil system was flushed.
- 31 pieces of equipment were boxed up.
- 22 motors were unclipped and run for 4 hr.
- The instrumentation connections were completed and reinstated.

After completion of the precommissioning activities, additional start-up precommissioning activities included purging, evacuating, and drying out the refrigerant and lube-oil circulation system with nitrogen to a 40° F. dewpoint; purging and drying out the absorber system with nitrogen to a 40° F. dewpoint; stroking and functionally testing all control valves; commissioning all pressure isolation valves; filling the refrigeration loop with propane and collecting samples to confirm that the system dewpoint was <–40° F.

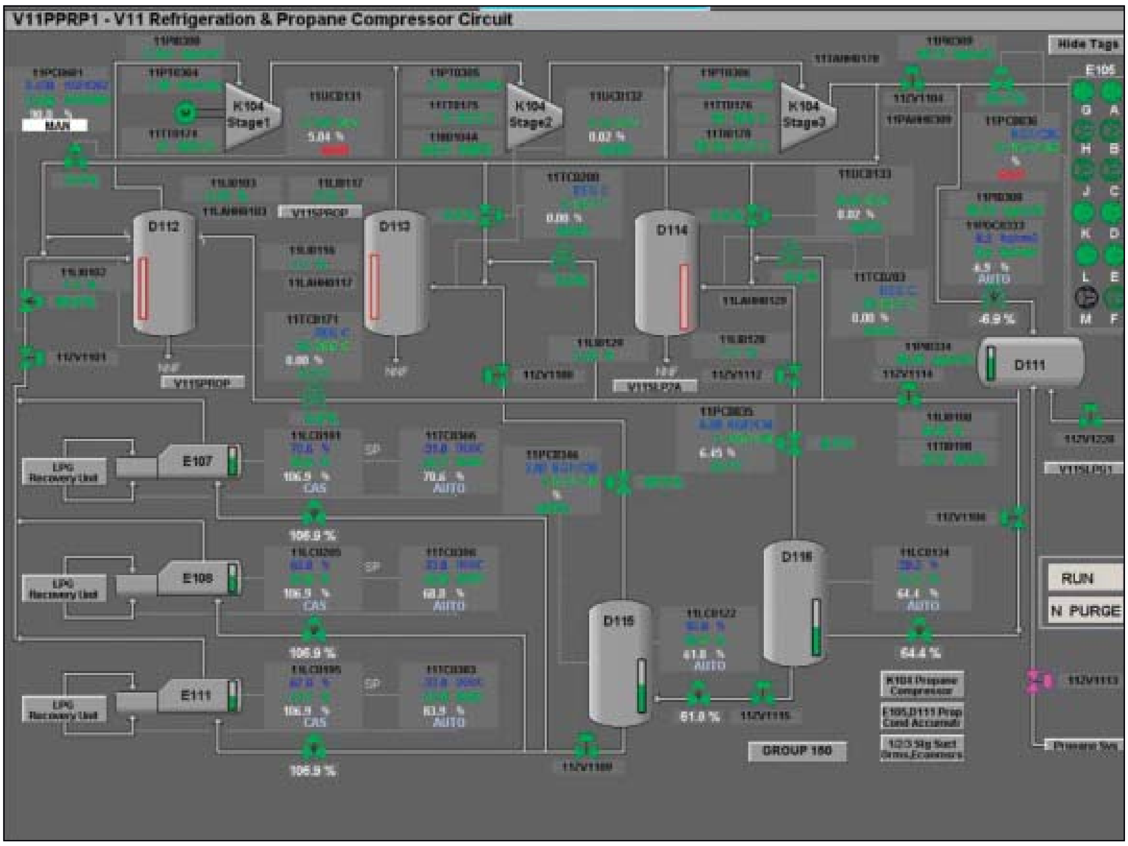
LPG-recovery process start-up

After completing all the commissioning activities and with the debutanizer producing a C_{5+} platformate product meeting the C_4 and lighter content specification, we determined that the available initial CCR net gas flow on June 18, 2006, was about 29.6 MMscfd. First, therefore, we initiated the flow of unstabilized platformate (bulk solvent) from the feed to the debutanizer at about 167 gpm.

Once the level in the bottom of the LPG absorber C-0101 was established at about 60% level transmitter (LT) range, we started the absorber bottoms pump G-109B to circulate bulk solvent through the two solvent cross-exchangers back to the debutanizer column feed.

After about an hour of established circulation for the bulk solvent, we initiated flow of the debutanizer bottoms (lean solvent) stream at about 150 gpm. After filling the piping and exchangers, the lean solvent level began to increase in the presaturation separator D-0110.

When the level was established at about 60% of the LT range, we started the presaturation pump G-0108A to transfer solvent to the absorber column's top. Within 20 min of starting



Here is the DCS system screen for the propane refrigeration compressor circuit after start-up of the refrigeration system (Fig. 7).

G-0108A, level in the absorber bottom started to increase, which indicated that the two solvent circulation loops were completed. The LT controlling flow from the discharge of the absorber bottoms pump G-0109B was switched to auto control.

With no gas flow through the absorber system, and after establishing lean solvent circulation, the column pressure started to decrease to about 122 psig from an initial pressure of about 142 psig. This indicated slight absorption of hydrocarbons even at warm solvent temperatures (98° F.).

To reestablish the pressure in the column to the CCR net gas compressor-suction drum pressure without flowing gas through the LPG-recovery unit, we reopened the inlet isolation valve. The isolation valve blocking flow from the LPG absorber overhead to the fuel-gas system remained closed. With the circulating warm solvent, the pressure increased and stabilized at about 139 psig.

When establishing the aforementioned two solvent circulation circuits, we identified several level and flow instrumentation calibration issues:

• *First circuit.* Between the debutanizer feed, cross-exchanger E-0110, platformate chiller E-0111, LPG absorber C-0101, absorber bottoms pump G-0109B, cross-exchangers E-0110 and E-0109, and debutanizer feed.

• *Second circuit.* Cool debutanizer bottoms from E-0102, cross-exchanger E-0109, mixer K-0101, presaturation chiller E-0108, presaturation separator D-0110, presaturation pump G-0108A, LPG absorber C-0101, absorber bottoms pump G-0109B, cross-exchangers E-0110 and E-0109, debutanizer feed

Before attempting to start the propane refrigeration system, we fixed all the instrumentation calibration issues during the next 24 hr. We subsequently initiated the flow of CCR net gas through the LPG-recovery process by opening the isolation valve at the outlet of the absorption system and closing the bypass isolation valve around the LPG-recovery unit.

Propane refrigeration start-up

With the established cooling load through the tube side of three chillers, we could start up the refrigeration system. Unfamiliarity of the refrigeration cycle within the refining industry as a whole was a significant obstacle for the operations team in developing the feel for starting and controlling a three stage, closed-loop propane refrigeration system.

Table 2 summarizes the 12 compressor trips and respective lessons learned that eventually resulted in a successful start-up of the three-stage centrifugal compressor and closed loop refrigeration cycle.

Although comparable quench-based suction drum configurations are quite extensively used at Saudi Aramco's gas processing facilities, a recurring problem in the start-up at Yanbú was managing and controlling liquid levels in the various suction drums.

The hydrocarbon processing industry uses large refrigeration systems without needing to add quench liquid into the compressor suction drums by simply routing the antisurge hot gas from the compressor discharge through a sparger line below the tube bundle in kettle chillers and in economizer drums where liquid refrigerant is normally present. This avoids the potential imbalance between the antisurge gas flows and quench-liquid temperature control valves, and also ensures that the compressor suction drums remain dry, which prevents compressor trips from high liquid level. This type of system at the Yanbú refinery would have simplified significantly the start-up of the refrigerant compressor.

When attempting to start up the compressor, we emphasized starting flow of refrigerant vapors as quickly as possible into the refrigerant compressor to keep the discharge temperature within limits and trying to close the antisurge gas and liquid quench flows to reduce overloading the compressor motor.

We realized after the twelfth trip that the inlet feed gas from the CCR unit was only about a third of the design gas flow. Also, an analysis of the compressor surge flows revealed that as long as the inlet gas flow from the CCR unit was less than 88% of the design flow for the LPG-recovery unit, the installed refrigeration compressor will always have its antisurge valve open.

This allowed us to change the start-up focus from trying to close the antisurge valve to managing the introduction of available refrigerant vapors generated from the process streams through the chillers. This was the final factor that led to the successful start-up of the refrigeration system. Within about 5 hr of continued integrated operation of the process-refrigeration systems, all temperatures reached their expected settings.

Fig. 6 shows a representative DCS display snapshot of the process flow. Fig. 7 shows a display snapshot of the refrigeration system.

The authors

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Further operations

Operation of the integrated LPG-recovery facility is easy, stable, and flexible to gas flow and composition changes. If the refrigeration compressor accidentally trips, the LPG-recovery process can continue to operate stably and await restart of the refrigeration compressor.

Operation of the Yanbú refinery unit has successfully demonstrated turn-down to 30% of the design inlet gas flow capacity. With this start-up, Yanbú refinery has successfully pioneered the incorporation of colder temperatures within a refining environment to maximize recovery of value from its hydrocarbon resources.

The unit has operated continuously and smoothly since starting up in July 2006. ✦

Nelson-Farrar Cost Indexes

Refinery construction (1946 Basis)

(Explained on p.145 of the Dec. 30, 1985, issue)

	1962	1980	2004	2005	2006	Feb. 2006	Jan. 2007	Feb. 2007
Pumps, compressors, etc.	222.5	777.3	1,581.5	1,685.5	1,758.2	1,736.9	1,799.2	1,829.5
Electrical machinery	189.5	394.7	516.9	513.6	520.2	509.1	527.7	526.8
Internal-comb. engines	183.4	512.6	919.4	931.1	959.7	953.1	969.5	969.5
Instruments	214.8	587.3	1,087.6	1,108.0	1,166.0	1,115.6	1,239.9	1,246.8
Heat exchangers	183.6	618.7	863.8	1,072.3	1,162.7	1,079.2	1,179.4	1,179.4
Misc. equip. average	198.8	578.1	993.8	1,062.1	1,113.3	1,078.8	1,143.2	1,150.4
Materials component	205.9	629.2	1,112.7	1,179.8	1,273.5	1,215.1	1,310.0	1,335.2
Labor component	258.8	951.9	2,314.2	2,411.6	2,497.8	2,475.5	2,558.6	2,558.6
Refinery (Inflation) Index	237.6	822.8	1,833.6	1,918.8	2,008.1	1,971.3	2,059.1	2,069.2

Refinery operating (1956 Basis)

(Explained on p.145 of the Dec. 30, 1985, issue)

	1962	1980	2004	2005	2006	Feb. 2006	Jan. 2007	Feb. 2007
Fuel cost	100.9	810.5	971.9	1,360.2	1,569.0	1,608.0	1,386.2	1,635.6
Labor cost	93.9	200.5	191.8	201.9	204.2	201.9	218.1	222.2
Wages	123.9	439.9	984.0	1,007.4	1,015.4	982.1	1,065.6	1,058.2
Productivity	131.8	226.3	513.3	501.1	497.5	486.5	488.5	476.2
Invest., maint., etc.	121.7	324.8	686.7	716.0	743.7	730.1	759.8	763.5
Chemical costs	96.7	229.2	268.2	310.5	365.4	357.9	363.4	367.1
Operating indexes								
Refinery	103.7	312.7	486.7	542.1	579.0	574.9	574.7	600.6
*Process units**	103.6	457.5	638.1	787.2	870.7	878.9	816.6	906.4

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

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

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

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Iran details LNG liquefaction plans

Hedayat Omidvar
National Iranian Gas Co.
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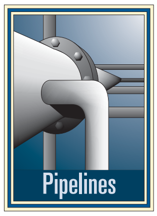


Iran's government actively supports building the country's natural gas liquefaction capacity as a means of commercializing production from its South Pars Phase 11-13 developments.

This article examines the background for this effort and some of Iran's competitive advantages before detailing the three liquefaction projects currently under way.

Background

Natural gas follows oil and coal in share of the global energy market, currently providing 23% of the world's energy needs.[1] Its share, however, has been growing.

Several factors have led to this growth, foremost among which have been:

• A sharp rise in proven natural gas reserves worldwide.

• The growing priority given by major oil importing countries to security and diversification of energy supplies.

• Growing concern for the environment.

Iran has the second largest proven natural gas reserves in the world. The country has published proven natural gas in-place of more than 27.57 trillion cu m, 18% of the world's total natural gas reserves.[1]

Iran's South Pars gas field, with 13.177 trillion cu m of natural gas and 19 million bbl of condensate, and its other large reservoirs are located primarily in shallow waters within a few kilometers of its coastline, making them easily accessible to relatively low cost development.

The advantageous location of these giant natural gas reserves allows for a variety of export alternatives:

• To the Pacific Rim as LNG.

• To Europe as LNG or via pipeline.

• To Pakistan and other neighboring countries via pipeline.

• To India and China as LNG or via pipeline.

• To other Far Eastern countries such as Japan and South Korea as LNG.

This article examines Iran's LNG-related plans for developing these resources, which the country's leadership has made a high priority in fueling the nation's continued growth.

Competitive advantages

A number of factors contribute to Iran's emergent strength as a global supplier of natural gas. These include:

• World-class, low cost gas resource base in the South Pars field.

• Significant condensate revenue stream to underpin LNG economics.

• Strategic geographic location.

• Strong government support for LNG exports.

• Access to a diverse technical and commercial workforce.

South Pars is a reliable gas resource with extremely competitive development costs. The high volume of condensates produced by the field provides a significant revenue stream. Based on experience gained from LNG projects elsewhere in the world, liquids revenues will play an essential role in underpinning overall project economics.

Iran is strategically located, with the potential to compete for markets in Europe, India, and Asia Pacific, a particular advantage given the increasingly competitive nature of the LNG market. Iran's government is keen to pursue this advantage by supporting development of the country's LNG liquefaction infrastructure.

In times of low domestic demand, gas currently delivered into Iran's domestic gas infrastructure could instead act as backup supplies for the LNG plants if upstream supplies are interrupted. This could be a crucial point in early development of the LNG projects and represents a competitive advantage over the majority of competitors, most of which lack a similarly developed domestic market.

Projects

• *NIOC LNG.* NIOC LNG is 100% owned by National Iranian Oil Co., directed by National Iranian Gas Export

Co. NIOC's board of directors awarded frontend engineering design in 2001 to a consortium of JGC and Technip.

NIOC expects to produce 10 million tonnes/year of LNG by 2010, using a two-train plant fed by almost 1.94 bcfd of natural gas from South Pars Phase 12.

NIOC divided the project into three packages to facilitate efficient implementation and increase use of domestic resources:

- Package I: Processing and condensation units, utility, offsite equipment, and the top section of the quay.
- Package II: LPG and LNG storage tanks and accessories.
- Package III: Sulfur, LPG, LNG, and condensate loading quays.

The plant will be located on Tombak Island, 60 km from Assaluyeh and will target Europe and Asia. It will use two 5-million tonne/year trains.

The plant will use Linde liquefaction technology, gas-phase mercaptan removal, six gas turbine compressor drivers arranged in parallel, Claus process sulfur recovery, and an acid-gas removal system from BASF through Lurgi Oil-Gas-Chemie GmbH. It will use a hybrid seawater-air cooling medium and steam as its heating medium. Six gas turbine electrical drivers will supply the plant's power.

Three 140,000-cu m containment tanks will hold LNG prior to loading.

- *Pars LNG.* NIOC (50%), Total SA (40%), and Petronas (10%) own this project, aimed at exporting 10 million tonnes/year of LNG to Europe, Asia, and the Far East. The plant will use two 5-million tonne/year trains.

The owners formed Pars LNG Ltd. in 2004 to handle frontend engineering design, market the second train's production, call for the engineering, procurement, and construction tenders, and finance development of the project.

Pars LNG has completed FEED work and expects to begin production by 2009. This plant will also be located on Tombak Island.

In addition to LNG, Pars expects the plant to produce 680,000 tonnes/year of LPG, 250,000 tonnes/year of condensate, and 700 tonnes/day of sulfur, using 2 bcfd of natural gas from South Pars Phase 11.

South Pars, Tombak liquefaction

Fig. 1

The plant will use Axens liquefaction technology, liquid phase cryogenic process mercaptan removal, and electric motor compressor drivers arranged in series. It will use a hybrid seawater-air cooling medium and steam as its heating medium. Gas turbines with heat recovery will supply the plant's power.

Three 155,000-cu m containment tanks will hold LNG prior to loading.

- *Persian LNG.* NIOC (50%), Shell (25%), and RepsolYPF SA (25%) own this project, aimed at exporting 16 million tonnes/year of LNG to Europe, Asia, and the Far East. The plant will use two 8-million tonne/year trains.

The owners signed a framework agreement in December 2004, following completion of feasibility studies. Frontend engineering design work is scheduled to begin June 2007, with production expected by early 2011. As with the other two facilities, this plant will be located on Tombak Island.

In addition to LNG, the Persian project expects to produce 1.5 million tonnes/year of LPG, 4.5 million bbl/year of condensate, and 200,000 tonnes/year of sulfur, using 2.8 bcfd of natural gas from South Pars Phase 13.

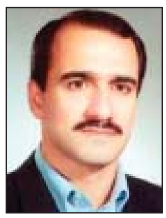
The plant will use Shell-DMR process liquefaction technology, Sulfinol-D molecular sieve mercaptan removal, and electric-motor compressor drivers. It will use an air cooling medium and have a combined-cycle power plant.

Three 160,000-cu m containment tanks will hold LNG prior to loading. A 65,000-cu m tank will hold butane and a 105,000-cu m tank propane. ✦

Reference

1. NIGC Annual Report, 2006.

The author



Hedayat Omidvar has been working since 1992 as a natural gas consumption expert in National Iranian Gas Co.'s corporate planning department. He currently heads NIGC's strategic studies, research, and technology department. Omidvar holds an MS (2002) in industrial engineering. He is a member of the Institute of Industrial Engineers, the American Industrial Hygiene Association, and serves on the marketing committee of the International Gas Union.

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New emulsion breaker; feedstock treatment

New products for emulsion breaking and feedstock treatment are on the market.

PetroLuxus 500 is a new aqueous emulsion-breaking product for drilling, production, refining, and storage.

It is a specially blended aqueous chemical solution developed for the treatment of hydrocarbon emulsions. When introduced into an emulsion, PetroLuxus 500 disperses rapidly while eliminating the interfacial surface tension between oil and other materials such as water, metals, dirt, sediments, and other contaminants.

The product works rapidly, usually within several hours, to effect separation of hydrocarbon emulsion components resulting in a stratification of materials by specific gravity. The company says that stratification of the emulsion components by specific gravity provides an efficient method for the remediation and recovery of the components. PetroLuxus(TM) 500 is nonhazardous, nonflammable, and biodegradable.

The product offers the opportunity to recover hydrocarbons and reduce former waste to nonhazardous, disposable, or salable materials.

PetroLuxus 500 can be utilized to break emulsions at all phases of crude oil production.

During the drilling phase it can be utilized to remediate drilling fluids-muds, tailings, and sludge pits. During the operational phase the product can be used to break emulsions at the wellhead, reduce water and particulates, and decrease viscosity in heavy oil. Emulsions created in the refining phase can be broken to maximize raw feedstock and processing final product. Storage facilities can utilize the product to clean and maintain tank batteries.

Feedstock treatment. PetroLuxus 100 is a new treatment for biodiesel, heavy oil, waste oil, and other raw fuel feedstocks.

The company says it is a cost effective, time efficient solution for upgrading raw fuel feedstocks before they enter the refining process or the treatment of finished product that has accumulated particulates and water during storage and transportation.

The specially blended treatment promises rapid dispersement that eliminates the interfacial surface tension of the feedstocks and other materials such as water, metals, dirt, sediments, and other contaminants. The product works rapidly, usually within several hours, to separate the components, resulting in a stratification of materials by specific gravity. The stratification of components provides a cleaner product for refining, the firm points out. PetroLuxus 100 is nonhazardous, nonflammable, and biodegradable.

It helps improve flow characteristics of heavy oil, segregate water, paraffin, and particulate matter, reduce acidity, reduce sulfur content, and reduce overall pumping costs, the company says.

Source: **Planet Resource Recovery Inc.**, 8815 Industrial Drive, Pearland, TX 77584.

Editor's note: Due to a holiday in the US, API data were not available at presstime.

OGJ GASOLINE PRICES

	Price ex tax 5-23-07	Pump price* 5-23-07	Pump price 5-24-06
	¢/gal		
(Approx. prices for self-service unleaded gasoline)			
Atlanta	265.8	305.5	285.7
Baltimore	262.9	304.8	292.7
Boston	256.1	298.0	286.7
Buffalo	247.4	307.5	296.7
Miami	267.5	317.8	299.7
Newark	254.9	287.0	284.6
New York	250.0	310.1	295.9
Norfolk	256.5	294.4	287.8
Philadelphia	258.8	309.5	300.6
Pittsburgh	246.4	297.1	285.7
Wash., DC	273.5	311.9	305.6
PAD I avg.	258.2	304.0	292.9
Chicago	310.3	361.2	317.0
Cleveland	266.2	312.6	278.2
Des Moines	269.8	310.2	265.7
Detroit	272.1	321.3	281.8
Indianapolis	277.5	322.5	275.0
Kansas City	273.1	309.1	265.0
Louisville	277.8	314.7	282.2
Memphis	248.2	288.0	277.7
Milwaukee	282.6	333.9	284.7
Minn.-St. Paul	275.3	315.7	272.7
Oklahoma City	273.1	308.5	259.7
Omaha	269.6	316.0	274.0
St. Louis	267.0	303.0	259.4
Tulsa	271.0	306.4	257.7
Wichita	265.8	309.2	264.0
PAD II avg.	273.3	315.5	274.3
Albuquerque	281.4	317.8	279.8
Birmingham	254.4	293.1	273.9
Dallas-Fort Worth	257.2	295.6	286.5
Houston	255.7	294.1	284.1
Little Rock	253.3	293.5	271.6
New Orleans	251.9	290.3	277.9
San Antonio	244.3	282.7	268.9
PAD III avg.	256.9	295.3	277.5
Cheyenne	268.3	300.7	263.6
Denver	276.5	316.9	282.5
Salt Lake City	271.4	314.3	287.5
PAD IV avg.	272.0	310.6	278.0
Los Angeles	288.0	346.5	331.4
Phoenix	272.7	310.1	303.5
Portland	296.6	339.9	297.5
San Diego	295.5	354.0	338.4
San Francisco	315.2	373.7	336.4
Seattle	293.1	345.5	314.5
PAD V avg.	293.5	345.0	320.3
Week's avg.	**269.4**	**313.0**	**286.5**
Apr. avg.	**234.7**	**278.3**	**270.5**
Mar. avg.	**210.4**	**254.0**	**235.4**
2007 to date	**213.0**	**256.6**	—
2006 to date	**206.9**	**249.7**	—

*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

Spot market product prices (5-18-07, ¢/gal)

	5-18-07 ¢/gal		5-18-07 ¢/gal
Motor gasoline (Conventional-regular)		Heating oil No. 2	
New York Harbor	236.58	New York Harbor	191.56
Gulf Coast	245.95	Gulf Coast	191.80
Los Angeles	251.20	Gas oil	
Amsterdam-Rotterdam-Antwerp (ARA)	226.34	ARA	191.45
Singapore	220.02	Singapore	198.33
Motor gasoline (Reformulated-regular)		Residual fuel oil	
New York Harbor	248.95	New York Harbor	125.90
Gulf Coast	243.08	Gulf Coast	130.83
Los Angeles	260.70	Los Angeles	148.88
		ARA	111.94
		Singapore	127.20

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

BAKER HUGHES RIG COUNT

	5-25-07	5-26-06
Alabama	4	4
Alaska	8	9
Arkansas	42	21
California	32	34
Land	31	27
Offshore	1	7
Colorado	101	92
Florida	1	0
Illinois	0	0
Indiana	2	0
Kansas	12	6
Kentucky	7	6
Louisiana	176	190
N. Land	54	58
S. Inland waters	23	19
S. Land	33	34
Offshore	66	79
Maryland	0	0
Michigan	1	2
Mississippi	13	8
Montana	20	21
Nebraska	0	0
New Mexico	80	99
New York	5	6
North Dakota	35	33
Ohio	13	6
Oklahoma	194	182
Pennsylvania	14	17
South Dakota	4	2
Texas	835	739
Offshore	12	13
Inland waters	1	5
Dist. 1	19	21
Dist. 2	23	26
Dist. 3	61	69
Dist. 4	99	83
Dist. 5	176	134
Dist. 6	121	102
Dist. 7B	36	41
Dist. 7C	56	37
Dist. 8	112	83
Dist. 8A	24	25
Dist. 9	36	30
Dist. 10	59	70
Utah	41	38
West Virginia	35	25
Wyoming	75	98
Others— NV-2; TN-4; VA-3; WA-1	10	3
Total US	**1,760**	**1,649**
Total Canada	**114**	**325**
Grand total	**1,874**	**1,974**
Oil rigs	287	265
Gas rigs	1,471	1,381
Total offshore	80	99
Total cum. avg. YTD	**1,740**	**1,557**

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 5-25-07	Percent footage* 5-25-07	Rig count 5-26-06	Percent footage* 5-26-06
0-2,500	59	8.4	58	—
2,501-5,000	106	50.0	94	50.0
5,001-7,500	236	20.7	221	18.5
7,501-10,000	422	2.8	377	3.1
10,001-12,500	432	2.7	370	2.9
12,501-15,000	272	0.3	276	0.3
15,001-17,500	97	1.0	105	—
17,501-20,000	78	—	73	—
20,001-over	37	—	22	—
Total	**1,739**	**7.6**	**1,596**	**7.0**
INLAND	44		42	
LAND	1,628		1,483	
OFFSHORE	67		71	

*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]5-25-07	[2]5-26-06
	1,000 b/d	
(Crude oil and lease condensate)		
Alabama	18	19
Alaska	786	801
California	671	690
Colorado	50	63
Florida	6	7
Illinois	33	28
Kansas	96	100
Louisiana	1,374	1,231
Michigan	15	17
Mississippi	51	48
Montana	92	97
New Mexico	165	163
North Dakota	107	110
Oklahoma	168	172
Texas	1,327	1,316
Utah	46	48
Wyoming	143	129
All others	62	64
Total	**5,210**	**5,103**

[1]OGJ estimate. [2]Revised.

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

US CRUDE PRICES

$/bbl*	5-25-07
Alaska-North Slope 27°	50.90
South Louisiana Sweet	68.25
California-Kern River 13°	55.25
Lost Hills 30°	63.40
Wyoming Sweet	60.95
East Texas Sweet	62.39
West Texas Sour 34°	54.90
West Texas Intermediate	61.75
Oklahoma Sweet	61.75
Texas Upper Gulf Coast	58.50
Michigan Sour	54.75
Kansas Common	60.75
North Dakota Sweet	56.25

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

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

WORLD CRUDE PRICES

$/bbl[1]	5-18-07
United Kingdom-Brent 38°	66.92
Russia-Urals 32°	63.43
Saudi Light 34°	63.77
Dubai Fateh 32°	64.36
Algeria Saharan 44°	70.20
Nigeria-Bonny Light 37°	70.22
Indonesia-Minas 34°	67.78
Venezuela-Tia Juana Light 31°	60.23
Mexico-Isthmus 33°	60.12
OPEC basket	65.24
Total OPEC[2]	64.90
Total non-OPEC[2]	62.75
Total world[2]	63.92
US imports[3]	60.29

[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]

US NATURAL GAS STORAGE[1]

	5-18-07	5-11-07	Change
	Bcf		
Producing region	717	695	22
Consuming region east	838	777	61
Consuming region west	287	275	12
Total US	**1,842**	**1,747**	**95**
	Feb. 07	**Feb. 06**	**Change, %**
Total US[2]	**1,649**	**1,886**	**–12.6**

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

PACE REFINING MARGINS

	Mar. 2007	Apr. 2007	May 2007	May 2006	Change	Change, % 2007 vs. 2006
	$/bbl					
US Gulf Coast						
West Texas Sour	16.43	23.69	30.23	18.13	12.10	66.8
Composite US Gulf Refinery	16.83	23.98	26.94	19.16	7.77	40.6
Arabian Light	17.50	24.84	27.02	19.03	8.00	42.0
Bonny Light	9.70	14.97	19.51	11.79	7.72	65.4
US PADD II						
Chicago (WTI)	16.98	25.93	39.15	17.29	21.86	126.5
US East Coast						
NY Harbor (Arab Med)	17.81	20.18	24.28	17.28	7.00	40.5
East Coast Comp-RFG	20.37	23.07	27.04	20.51	6.52	31.8
US West Coast						
Los Angeles (ANS)	29.31	30.05	30.00	26.26	3.73	14.2
NW Europe						
Rotterdam (Brent)	3.43	4.69	8.25	4.09	4.15	101.4
Mediterranean						
Italy (Urals)	8.79	10.27	13.22	11.52	1.70	14.8
Far East						
Singapore (Dubai)	7.93	8.89	10.20	5.69	4.51	79.2

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

US NATURAL GAS BALANCE DEMAND/SUPPLY SCOREBOARD

	Feb. 2007	Jan. 2007	Feb. 2006	Feb. 2007-2006 change	Total YTD 2007	Total YTD 2006	YTD 2007-2006 change
	bcf						
DEMAND							
Consumption	2,532	2,452	2,152	380	4,984	4,325	659
Addition to storage	50	56	54	–4	106	164	–58
Exports	56	76	59	–3	133	115	18
Canada	19	39	33	–14	58	65	–7
Mexico	32	32	20	12	65	39	26
LNG	5	5	6	–1	10	11	–1
Total demand	**2,638**	**2,584**	**2,265**	**373**	**5,223**	**4,604**	**619**
SUPPLY							
Production (dry gas)	1,585	1,610	1,557	28	1,585	1,557	28
Supplemental gas	6	6	6	0	6	6	0
Storage withdrawal	740	441	374	366	1,522	913	609
Imports	308	382	326	–18	691	682	9
Canada	264	329	282	–18	593	602	–9
Mexico	0	0	5	–5	0	2	–2
LNG	44	53	39	5	98	78	20
Total supply	**2,639**	**2,439**	**2,263**	**376**	**3,804**	**3,158**	**646**

NATURAL GAS IN UNDERGROUND STORAGE

	Feb. 2007	Jan. 2007	Dec. 2006	Feb. 2006	Change
	bcf				
Base gas	4,214	4,215	4,211	4,204	10
Working gas	1,649	2,379	3,070	1,886	–237
Total gas	**5,863**	**6,594**	**7,281**	**6,090**	**–227**

Source: DOE Monthly Energy Review.
Data available in OGJ Online Research Center. NOTE: No new data at press time.

WORLDWIDE NGL PRODUCTION

	Feb. 2007	Jan. 2007	2 month average – Production – 2007	2006	Change vs. previous year Volume	%
	1,000 b/d					
Brazil	88	86	87	87	—	0.5
Canada	763	718	741	706	34	4.9
Mexico	405	411	408	437	–29	–6.6
United States	1,706	1,670	1,688	1,681	8	0.4
Venezuela	200	200	200	200	—	—
Other Western Hemisphere	158	166	162	167	–5	–2.9
Western Hemisphere	**3,320**	**3,251**	**3,286**	**3,277**	**9**	**0.3**
Norway	311	315	313	305	9	2.8
United Kingdom	164	168	166	165	1	0.8
Other Western Europe	20	19	19	20	–1	–2.8
Western Europe	**495**	**503**	**499**	**490**	**9**	**1.9**
Russia	397	396	397	410	–14	–3.3
Other FSU	160	160	160	160	—	—
Other Eastern Europe	17	16	16	20	–3	–17.3
Eastern Europe	**574**	**572**	**573**	**590**	**–17**	**–2.9**
Algeria	340	341	341	295	46	15.4
Egypt	65	65	65	65	—	—
Libya	60	60	60	60	—	—
Other Africa	197	197	197	180	17	9.3
Africa	**662**	**663**	**662**	**600**	**62**	**10.4**
Saudi Arabia	1,510	1,510	1,510	1,460	50	3.4
United Arab Emirates	400	400	400	400	—	—
Other Middle East	681	681	681	670	11	1.6
Middle East	**2,591**	**2,591**	**2,591**	**2,530**	**61**	**2.4**
Australia	75	75	75	75	—	0.1
China	180	180	180	180	—	—
India	—	38	19	43	–24	–55.9
Other Asia-Pacific	219	220	220	221	–1	–0.5
Asia-Pacific	**474**	**513**	**494**	**519**	**–25**	**–4.8**
TOTAL WORLD	**8,116**	**8,092**	**8,104**	**8,005**	**99**	**1.2**

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

OXYGENATES

	Feb. 2006	Jan. 2006	Change	YTD 2006	YTD 2005	Change
	1,000 bbl					
Fuel ethanol						
Production	10,795	11,621	–826	22,416	17,394	5,022
Stocks	8,749	8,593	156	8,749	7,376	1,373
MTBE						
Production	1,821	1,797	24	3,618	6,262	–13,776
Stocks	1,792	2,215	–423	1,792	3,032	–1,240

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

US HEATING DEGREE DAYS

	Apr. 2006	Apr. 2005	Normal	2007 % change from normal	Total degree days July 1 through Apr. 30 2007	2006	Normal	% change from normal
New England	641	511	583	9.9	6,025	5,735	6,264	–3.8
Middle Atlantic	547	401	496	10.3	5,311	5,040	5,655	–6.1
East North Central	548	379	510	7.5	5,972	5,544	6,209	–3.8
West North Central	539	329	472	14.2	6,209	5,691	6,493	–4.4
South Atlantic	225	122	179	25.7	2,613	2,556	2,785	–6.2
East South Central	285	120	216	31.9	3,378	3,206	3,521	–4.1
West South Central	171	39	94	81.9	2,238	1,890	2,269	–1.4
Mountain	388	340	426	–8.9	4,676	4,421	4,894	–4.5
Pacific	279	338	298	–6.4	2,776	2,867	2,970	–6.5
US average*	**382**	**275**	**345**	**10.7**	**4,119**	**3,899**	**4,326**	**–4.8**

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

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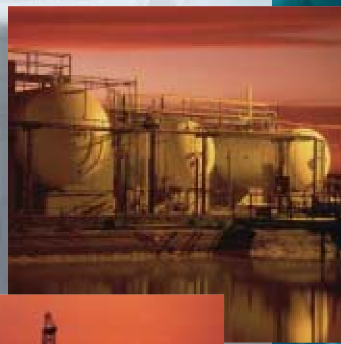

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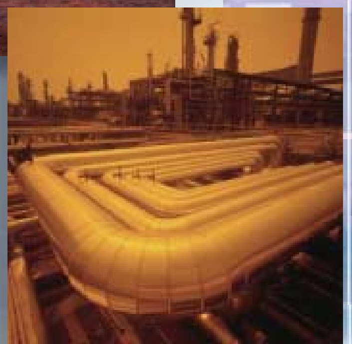

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International Ethylene Survey — Information on country, company, location, capacity, etc. Updated in March.
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LNG Worldwide — Facilities, Construction Projects, Statistics LNGINFO $395.00 US

Worldwide Construction Projects — List of planned construction products updated in May and November each year.

	Current		Historical 1996–Current	
Refinery	E1340	$395.00 US	E1340C	$1,495.00 US
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U.S. Pipeline Study — There are 14 categories of operating and financial data on the liquids pipeline worksheet and 13 on the natural gas pipeline worksheet.
E1040 $545.00 US

Worldwide Survey of Line Pipe Mills — Detailed data on line pipe mills throughout the world, process, capacity, dimensions, etc.
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Congress follows the Take That! energy approach

The Editor's Perspective

by Bob Tippee, Editor

Welcome to the Take That! approach to energy legislation.

The strategy has one advantage. Politicians who apply it never have to learn anything about energy. In fact, the approach works best when lawmakers and their constituents stay wholly ignorant about the subject.

Instead of creating effective and affordable solutions to real and complex problems, the Take That! approach conjures up villains to flail. The drama and simplicity especially appeal to children, young adolescents, and surprisingly many US politicians of more advanced age.

The US Congress has implemented Take That! energy legislation on several fronts recently. A new House energy bill would repeal several provisions of the Energy Policy Act of 2005 that tried to fortify US supplies of oil and natural gas.

Take that, oil companies!

Another House bill would make vaguely defined "price-gouging" a criminal offense.

Take that, oil companies!

Lawmakers in a Joint Economic Committee hearing have discussed breaking up major oil and gas companies.

Take that, oil companies!

Yet another House bill would enable the US government to sue the Organization of Petroleum Exporting Countries for price manipulation.

Take that, OPEC!

See how it works? Take That! energy legislation doesn't address real problems. For example, investigation after investigation has found no price-gouging by US refiners. The problem doesn't exist. Claims to the contrary are demonstrably false.

Yet the House sees fit to legislate against it. Doing so presupposes villainy where none exists. While promising action in June on a Senate version of the price-gouging legislation, Senate Majority Leader Harry Reid (D-Nev.) deployed the Take That! approach with characteristic aplomb.

"We think anything we do should have some effect on the gluttony of the oil companies," he said.

The Take That! approach gives political heroes like Reid dragons to slay. After all, political heroes who know nothing about the problems before them need dragons to slay. So they lash out at suppliers of fuels in short supply. To the extent they succeed they'll make demand ever harder to meet. And prices will rise even more.

So take that, oil consumers! And never forget who did it to you.

(Online May 25, 2007; author's e-mail: bobt@ogjonline.com)

Market Journal

by Sam Fletcher, Senior Writer

Market waffles prior to driving season

Crude futures prices waffled during trading sessions prior to the extended Memorial Day weekend May 26-28 that marked the start of the US summer driving season.

The June contract for benchmark US sweet, light crudes gained $1.33 to $66.27/bbl May 21 on the New York Mercantile Exchange, the highest closing since Apr. 27. It traded at $64.80-66.35/bbl May 22 before expiring at $64.97/bbl in the biggest 1-day price decline since May 4.

The new front-month July contract lost $1.36 to $65.51/bbl on May 22. It traded as high as $66.20/bbl May 23 before closing at $65.77/bbl. On May 24, it bounced between $63.82 and $66.15/bbl before closing at $64.18/bbl, the lowest level in more than a week, while in the UK North Sea Brent crude for July broke through $71/bbl, a 9-month high, before settling at $70.72/bbl.

"As a consequence, the Brent-West Texas Intermediate spread widened as much as $6.54/bbl," said analysts at Barclay's Capital, the investment banking division of Barclays Bank PLC, London.

Analysts in the Houston office of Raymond James & Associates Inc. said, "We continue to believe the Brent crude contract more accurately depicts the tight global oil market, along with underlying supply risks associated with Nigeria and Iran, and would expect this premium over WTI to dissipate once the localized glut is eliminated."

Traders ignored the loss of 100,000 b/d of production when BP PLC partially shut in Prudhoe Bay oil field May 22 after 20 bbl of water produced from the field leaked through a "pencil-sized" hole in a pipeline and was contained by BP. Officials expected to have the leak repaired within a week. That field normally produces 400,000 b/d.

US gasoline stocks increased by 1.5 million bbl to 196.7 million bbl in the week ended May 18, still well below average for the time of year. Commercial US crude inventories rose by 2 million bbl to 344.2 million bbl.

Valero refinery

On May 24, Valero Energy Corp. shut down part of its 158,000 b/d McKee refinery in Sunray, Tex., due to a catalyst circulation problem. "We are still evaluating the problem, but we expect the unit to be operating within 2 weeks. We expect that this will result in a loss of production of 30,000 b/d of gasoline and 3,000 b/d of jet fuel while the maintenance is ongoing. On the other hand, we will be able to increase production of ultralow-sulfur diesel at the plant by 11,000 b/d," said a company spokesman. "We expect to reduce crude rates slightly to 80,000 b/d. This issue will not affect our plans to increase overall throughput at the plant to 150,000 b/d by the end of June."

Meanwhile, Jerry Taylor, senior fellow at the Cato Institute, said US motorists had no reason to worry about fuel costs over Memorial Day. "High [gasoline] pump prices are not reducing demand because they are not imposing anything like the economic pain politicians allege," he said. Adjusting nominal 1949 gasoline prices of 27¢/gal for inflation, he said, "We get a price of $1.90/gal in today's terms. If we further adjust those prices by mean disposal income, we find that gasoline prices would have to be $6.68/gal before they were taking the same bite out of our wallets as they were in 1949.

In 1962—a year writ large in the popular imagination as the quintessential year of muscle cars and cheap gasoline thanks to [the movie] American Graffiti—gasoline prices averaged 31¢/gal. When disposable income is considered, today's gas would have to cost $4.48/gal to be a comparable burden."

Taylor said, "The public likewise thinks of 1972 as the last year of energy innocence prior to the rise of the Organization of Petroleum Exporting Countries and the onset of shortage. Fuel prices in 1972 averaged 36¢/gal—a hefty $2.77/gal in today's terms. While still high, this price is not all that different than the prices we were paying earlier in the year."

The US sent nine warships through the Strait of Hormuz in a major show of force May 23. "The ships are anticipated to commence exercises after traversing the waters to reassure neighboring countries of US commitment to localized security (the move is said to be a symbolic demonstration, as opposed to an inciting flex of muscle)," said Raymond James.

Elsewhere, the US National Oceanic & Atmospheric Administration forecast a 75% chance that activity in the 2007 Atlantic hurricane season will be above average, with 13-17 tropical storms anticipated and 7-10 of these expected to develop into hurricanes and 3-5 expected to become major hurricanes.

(Online May 25, 2007; author's e-mail: samf@ogjonline.com)

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Seismic Equipment and Services

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Technology Forum

Seismic Equipment and Services

Supplement to *Oil & Gas Journal* • June 4, 2007

Rubber-tracked vibrators travel in the shadow of a pyramid in Egypt while on task for WesternGeco, a division of Schlumberger. New technology solutions for land as well as marine seismic data acquisition are discussed in this special supplement. *Photo courtesy of WesternGeco.*

Oil & Gas Journal's Technology Forum series, produced by the OGJ Group Publisher, supplements the magazine with topical features on cutting-edge technology, services, and equipment, all expertly written from the technology provider's perspective. Inquiries should be directed to Bill Wageneck, Group Publisher, at billw@pennwell.com.

Seismic business evolving amid industry upturn

Even as activity rebounds strongly in the oil and natural gas seismic sector, that business continues to evolve in new directions.

Rapidly advancing technology is one of the key drivers of that evolution, coming in response to the changing technology needs of operators as they venture into more challenging geologic and geographic environments.

Industry specialists also see a seemingly contradictory pair of trends in the seismic sector: increased specialization by new niche companies and horizontally expanded service offerings for "one-stop shopping" by established firms.

Given the revenue growth prospects for the oil and gas industry today, the future of the seismic industry is decidedly bright—and there is substantial room for growth.

"Oil and gas companies continue to ramp up their exploration expenditures to take advantage of these historically high price levels and to attempt to sustain production in an era in which oil and gas is becoming harder to find and more costly to produce," says Robert Peebler, president and CEO of I/O (Input/Output Inc.) "While seismic expenditures have grown at a 10–15% annual rate over the last several years, comparable to the growth of the overall E&P sector, seismic still accounts for only $10 billion of the $300 billion total annual E&P spend."

"While seismic expenditures have grown at a 10–15% annual rate over the last several years, comparable to the growth of the overall E&P sector, seismic still accounts for only $10 billion of the $300 billion total annual E&P spend."

— Robert Peebler, I/O

Technology R&D the key

Operators and seismic companies working more closely together on R&D to develop new technologies mark the changing dynamic of the seismic business today, according to Jim Sledzik, marketing director for WesternGeco, a division of Schlumberger Ltd.

"Due to the current shortages in supply, seismic service providers and oil companies are communicating closely to find the most efficient way to get the optimum value out of the available resources," he says. "This exercise brings better and more disciplined resource management and asset prioritization through a more open relationship."

Sledzik also contends that by managing both local and global considerations in the planning and execution of projects, seismic firms are able to further enhance the opportunities for new technologies to deliver value that lowers E&P risk.

"This may take the form of long-term relationships where we work with operators to understand the 4D, or time-lapse, response of producing assets to multicompany collaboration, including interpretation and modeling, on multiclient projects."

A strong commitment to R&D is critical in the changing oil and gas industry environment, Sledzik adds.

"Key to addressing ever-more complex E&P challenges will be to maintain a scale and commitment to R&D that can create and enable new game-changing technologies," he says. "Increasingly, successful R&D is defined not just in the development of singular technologies or products, but, more importantly, integrated solutions, which leverage the benefits of a suite of component technologies. This philosophy led to the development of WesternGeco Q-Technology and continues to guide the direction of our R&D strategy.

"These integrated solutions must not only answer key technical challenges but also increase oil field productivity per employee—a goal that is increasingly enhanced by bringing together the collaborative knowledge and expertise of all parties involved."

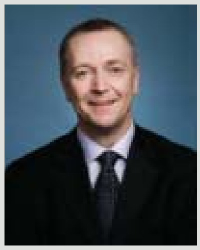
Technology the driver

Evolving technology drives the seismic industry's own evolution, contends Leon Thomsen, president of the Society of Exploration Geophysicists and chief geophysicist for BP PLC.

"Increased oil and gas commodity prices have been accompanied by corresponding increases in the costs to find and produce hydrocarbons; these costs set the scale for the associated geophysical investment," he notes. "If a small fraction (say 10%) of the expenditures of a resource company in procuring the acreage and drilling a well is spent on geophysical data acquisition and analysis, it can potentially yield much larger payoffs by ensuring the well is drilled in the right place and in the right way.

"The geophysical investment decisions should be governed by the expected added value in reducing risk. Thus, instead of doing more of the same type of geophysical data acquisition,

"We have seen seismic service companies emerging from being pure acquisition companies into full-fledged geosciences companies, offering a broad range of G&G services and technologies, taking over a significant part of R&D that used to take place within the oil companies, and building organizations that have deeper insights into prospectivity and the reservoirs."



— Sverre Strandenes, PGS

processing, and interpretation, it should be tailor-made to the problems at hand."

That point is underscored by the need to implement some of the more advanced geophysics and novel techniques for the greater challenges in exploration and production today, along with more attention to integration with other data, says Thomsen.

"These points are increasingly well-understood by the resource companies and clients of the seismic industry, and their demands on the seismic industry reflect this. To respond to this demand, the seismic industry is evolving, in its corporate structure as well as its seismic products."

Consolidation effects

There are several factors relating the changing structure of the seismic industry to the advancement of seismic technology, according to Steve Jumper, president and CEO of Dawson Geophysical Co.

"Consolidation among both seismic contractors and major oil companies has left fewer participants committed to research and development, particularly in seismic data acquisition technology," he says. "In addition, the cyclical nature of our business has made it more difficult to consistently secure adequate funding for noneconomic projects.

"Despite these burdens, the seismic contractors, equipment manufacturers, and major oil companies remaining have done a remarkable job of advancing technology in a very difficult environment, as is evident by the images we are producing today."

Changing roles

The roles of many service companies in the seismic business are evolving as well, contends Sverre Strandenes, group president, data processing and technology, Petroleum Geo-Services SA.

"We have seen seismic service companies emerging from being pure acquisition companies into full-fledged geosciences companies, offering a broad range of G&G services and technologies, taking over a significant part of R&D that used to take place within the oil companies, and building organizations that have deeper insights into prospectivity and the reservoirs."

Conversely, more niche companies are emerging in the seismic business in response to the traditionally slow uptake of technology in the oil and gas industry, Strandenes contends.

"In the current market, we see the emergence of a large number of new and small players providing acquisition capacity into an undersupplied market," he says. "These new players offer limited technology and scope and will not have the capability of the larger and broader geophysical companies to provide solutions and services covering the whole value chain."

The undersupply of seismic capacity, in combination with new and emerging players offering limited scope of services, may in fact slow down the implementation of new and existing high-end technology, Strandenes adds.

"We also see that the industry is moving to a phase of more specialized services as technology and business environments require new models of operation," he points out. "There will be closer relationships and cooperation between oil and service companies, where traditional boundaries will be replaced by alliances where risk and reward is a common objective for both parties."

Land seismic

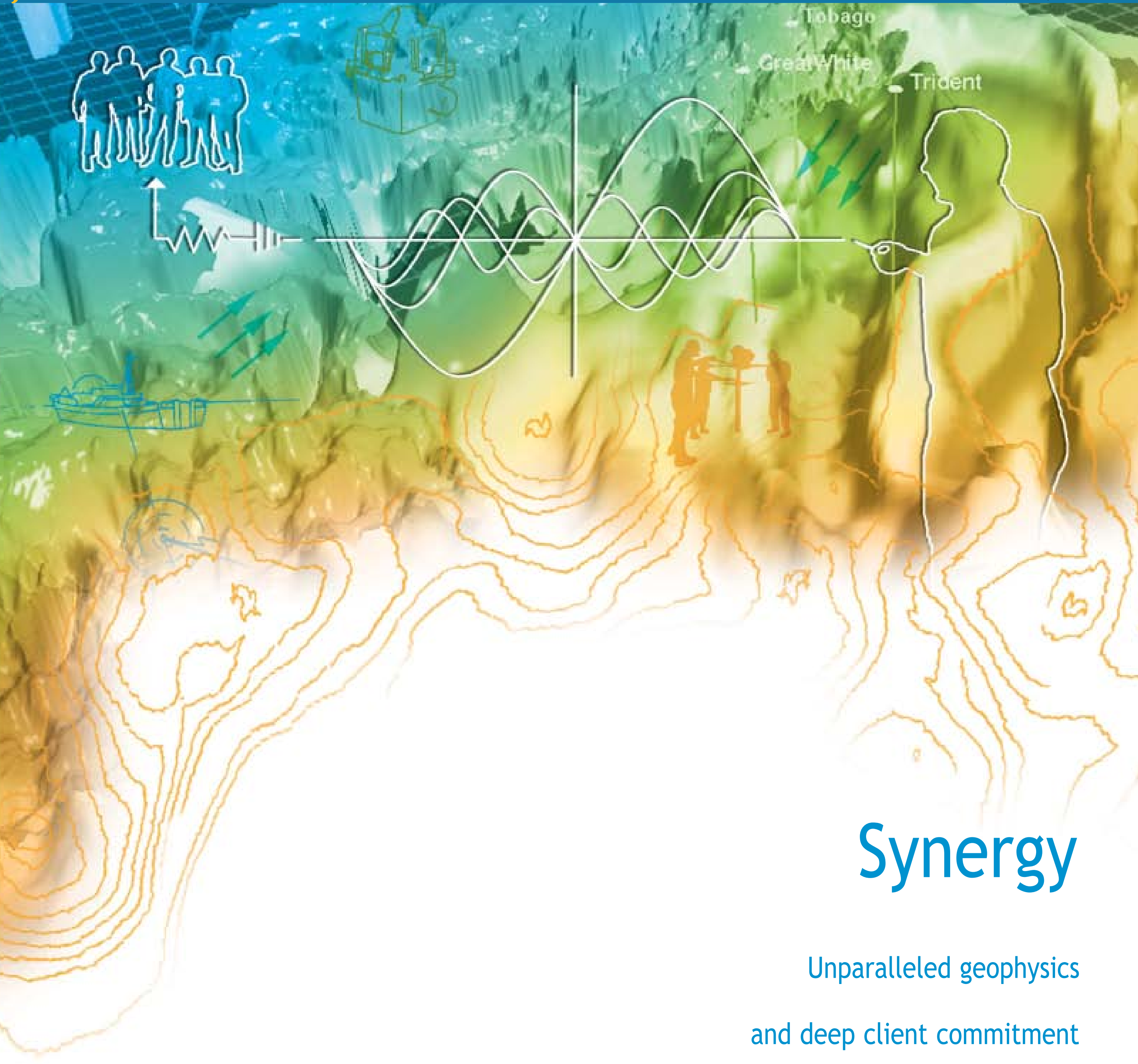
Land seismic imaging presents serious challenges to operators and seismic contractors alike.

It's been said that onshore data are hugely undersampled, with the average seismic crew carrying 2,000–4,000 channels on a land survey today, which some see as an order of magnitude less than what they should be carrying.

In addition, compared with marine seismic, land surveys are slow, costly, and pose greater safety and environmental risks.

Peebler lists these trends marking the land seismic business today:

- 15–20% annual growth in the number of active land seismic crews worldwide.
- Operators' desire to increase sampling densities to improve the quality and utility of land seismic images.
- More than $100 million (40%) growth in sector revenues from land systems since 2004.
- Growing sector backlogs for key technologies, including vibroseis vehicles, geophones, and land systems.
- Increasing pressures on the health, safety, and environmental aspects of land seismic operations.
- Growing interest in cableless acquisition methods, increasing the acceptance of both three-component digital sensors and full-wave imaging.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Marine seismic

In the marine seismic arena, a drive toward improving acquisition productivity and spatial sampling is resulting in ever-increasing numbers of streamers and greater efforts to position and control them, according to Peebler.

He also ticks off these trends in the marine seismic business:

- Exploration for prospects in deeper waters and deeper in the geologic column.
- More than 20 new marine vessels expected to enter the market before 2009.
- A move toward more and longer streamer cables and tighter streamer spacing to increase sampling densities and improve image quality.
- Introduction of complex acquisition geometries (such as wide- and multi-azimuth) to better image subsalt targets.
- More than $200 million (60%) growth in sector revenues from marine equipment since 2004.
- Growing sector backlogs for key technologies, especially streamer cables.
- Increasing penetration of new acquisition platforms, including node systems and full-wave seabed systems.
- Introduction of new processing algorithms, such as beam migration and reverse time migration.]

Structural, technological changes create new seismic business opportunities

Even as it adapts to structural and technological change amid a new oil and natural gas industry boom, the seismic sector faces a wealth of new business opportunities.

Propelled by high commodity prices, nonconventional oil and gas exploration and production activity is experiencing rapid growth. And there will be fresh opportunities in areas outside of traditional oil and gas operations, such as a push for carbon dioxide sequestration in response to a mounting global clamor to reduce greenhouse gas emissions.

That said, the seismic sector will continue to rely most heavily on its bread-and-butter business: conventional oil and gas exploration and development.

"Seismic data will always play a major role in the exploration for and exploitation of oil and natural gas resources," says Steve Jumper, president and CEO, Dawson Geophysical Co. "As subsurface features become more subtle and drilling risk increases, our industry will be forced to respond with cost-effective technology to improve subsurface images and reduce finding costs."

Reservoir characterization/monitoring

Even within the context of oil and gas operations, there is a shift under way in the seismic business toward more emphasis on reservoir characterization and monitoring.

"Our industry is expanding its knowledge of the information carried in conventional seismic data, not to mention multicomponent data, and how those data relate to well data, engineering data, and geologic information," Jumper points out. "Once we further integrate conventional—as well as multicomponent—seismic data with other information available from the production and development of a reservoir, the door will open for increased utilization of seismic technology on the production side of the E&P business." He adds, "As we discern more information about the reservoir rock, the use of seismic technology in the life cycle of an oil and gas asset will be extended."

> "Once we further integrate conventional—as well as multicomponent—seismic data with other information available from the production and development of a reservoir, the door will open for increased utilization of seismic technology on the production side of the E&P business."
>
> *– Steve Jumper, Dawson Geophysical*

That view squares with the evolving philosophy of WesternGeco, a division of Schlumberger. Jim Sledzik, WesternGeco marketing director, notes that the traditional role of seismic technology tended to mimic the conventional view of the life cycle of a field: a linear process starting with exploration and ending with abandonment. "Conventional seismic technology has delivered subsurface images,

and buying decisions have been dictated by immediate imaging needs within the cycle, but without significant consideration for future imaging requirements," he says. "In addition, conventional seismic data are rarely of sufficient resolution or fidelity to reliably extrapolate quantitative maps of reservoir properties, such as porosity."

Today's dynamic E&P environment demands much more, and advanced seismic technology plays a key role, Sledzik contends.

"With brownfield exploration, step-out exploration, and exploration near existing facilities, the life cycle of a reservoir becomes a continuous loop. Seismic data buying decisions must take this into account," he says.

WesternGeco describes this cycle as the Geophysical Continuum, defined as the connected life cycle of an oil field, where uncertainty is reduced by using high-fidelity geophysical measurements that are consistently calibrated with all other oil field measurements throughout the cycle.

"WesternGeco developed Q-Technology to deliver advanced seismic measurements that can span the life of a reservoir, from providing the best exploration images to delivering quantitative rock and fluid properties for development and production," Sledzik points out. "The key to unlocking this potential lies in making fundamentally better seismic measurements that deliver greater reservoir detail, allowing seamless calibration with other geophysical and borehole data."

Structural change

Perhaps the most significant new business opportunity for companies in the seismic sector will come as a result of the oil and gas industry's own structural changes.

"We see a need to change the modus operandi of the larger seismic companies," says Sverre Strandenes, group president, data processing and technology, Petroleum Geo-Services AS. "A company like PGS has a very large, global, and unique seismic database, combined with deep insights into the various hydrocarbon basins of the world.

"While a seismic database provides a tremendous value to an oil company—constituting the fundamental basis for defining and drilling prospects—in the hands of a service company, these data are valued quite differently. Therefore we see scope to change roles between oil companies and service companies—with the service companies moving higher up in the value chain—becoming a partner to oil companies rather than a pure service provider. This implies tighter relationships when it comes to developing new technologies and different business models and risk/reward sharing on commercial projects."

Business models for geophysics are evolving, permitting some fast-moving teams and organizations to respond with full-service capabilities that are highly cost-effective and competitive, contends Fred Aminzadeh, president-elect of the Society of Exploration Geophysicists (SEG) and president and CEO of dGB USA: "The industry is in a new age of true 'integration.' The new integration includes multidisciplinary technical work and data fusion, as well as new business collaboration models with open source software approaches. All of these efforts target lowering of exploration cost and reducing uncertainty and risks associated with drilling energy opportunities."

Technology role

New technology will play a key role in creating new business opportunities for seismic companies as well.

"Geophysics can help operators drill wells, not only in the right place, but also in the right way," says Aminzadeh. "This means, for example, assisting drilling by predicting overpressures and detecting geohazards. One recent successful application of seismic methods in this area is the use of 'gas chimney' technology. Gas 'chimneys,' or 'clouds'—both in the overburden above some hydrocarbon reservoirs and below reservoirs—are the result of the seepage of gas over geologic time or migration of hydrocarbon from source. The associated effects in seismic data were often, in the past, filtered out as noise. Modern gas chimney seismic technology instead attempts to utilize such information to assess seal and charge risk, better understand the hydrocarbon migration pathways, and detect shallow gas hazards."

Leon Thomsen, current SEG president and principal geophysicist at BP PLC, sees opportunity in revitalizing old fields through 4D (time-lapse) guidance of enhanced recovery processes: "Advances in 4D seismic in the form of permanently installed seismic monitoring systems (a part of the 'instrumented oil field') are expected to help the EOR process by guiding optimum placement of the injection wells and directional infill drilling."

Even booking and certifying reserves will create new business for seismic companies, Aminzadeh contends, namely estimating reserves by augmenting wellbore methods with surface geophysical methods in order to quantify different risk factors away from wells.

"While historically, engineers and geologists have been mostly responsible for reserve estimation, recent advances in various geophysical methods and the role they play in quantifying and risking different factors that go into the reserve estimation process (volumetrics, saturation, permeability, and recovery factor) make it absolutely crucial for the participation of geophysicists in booking the reserves and their certification," he says.

Emerging opportunities

Seismic technology also will play an increasingly important role in exploiting the emerging energy resources of tomorrow. Of special interest are applications of geophysical technology in developing unconventional hydrocarbon resources such as gas shales, tight sands, and coalbed methane.

"Various geophysical techniques, such as multicomponent seismics, well-to-well tomography, and passive seismics are candidates for such applications," Thomsen points out. "The fundamental point is that these emerging resources are more expensive to tap—that is why they are just now emerging.

"Whenever you do something expensive in the subsurface, it pays to understand the subsurface very well, in order to control that expensive process. This is where geophysics comes in."

What could emerge as a hitherto unexpected boom area of business for seismic companies, notes Strandenes, is that "when it comes to reducing the impact of emissions of carbon into the atmosphere, seismic may play a significant role in terms of defining potential reservoirs for deposition of, for instance CO_2, and in the monitoring of storing these accumulations in the subsurface."

Thomsen concurs, adding that discipline integration is critical for sequestering CO_2: "CO_2 sequestration, as well as exploration for CO_2 and its proper use in EOR, is also an area where geophysical methods have a lot to offer, especially in properly imaging the subsurface compartments where CO_2 is present and ensuring it is properly sealed."

Sledzik lists these areas as focal points for key applications of advanced seismic in emerging resource plays:

- Fracture corridor mapping in carbonates and unconventional gas plays.
- Seismic reservoir monitoring.
- Heavy oil and tar sands: "Changes in drilling economics are now increasing the use of seismic, especially for 4D applications where operators need to understand the efficacy of their steamflood operations."
- Formerly "marginal" subsalt and sub-basalt reserves that are becoming increasingly economic through a spectrum of E&P technologies.

"New technologies in geophysics and seismic will play a continuing and significant role in reducing technical risk in extracting hydrocarbons from these challenging resources," Sledzik adds.]

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— Fred Aminzadeh, SEG president-elect

Integration the key driver in seismic technology today

Seismic technologies continue to make rapid advances in response to a robust but technically more challenging industry environment.

Even as the sector continues to break new ground in a host of technologies, a new paradigm is emerging in how these advanced technologies are being integrated to provide the most detailed and accurate picture of the subsurface yet.

Integrating technologies

Steve Jumper, president and CEO of Dawson Geophysical Co., doesn't foresee a single game-changing technology, but rather a combination of technologies.

"For example, the use of multicomponent seismic data technologies may lead to improvements in reservoir characterization and production monitoring onshore," he notes. "The most efficient way to handle multicomponent recording will be with digital sensors. The channel count required to properly image a reservoir will necessitate some form of wireless recording system."

Integrating technologies is becoming more essential with the high risks associated with the increasingly geologically challenging plays operators encounter today.

"With deepwater wells costing $25 million or more to drill, operators face three main challenges—reducing exploration risk, reducing upfront costs, and protecting their investment," notes Jim Sledzik, marketing director for WesternGeco, a division of Schlumberger. "They can accomplish these objectives by using complementary technology to narrow the search and improve the likelihood they will discover a hydrocarbon-bearing structure before they spud the first well."

A seamless integration of the many geophysical datasets available is key, says Sledzik: "Bathymetry and gravimetry

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— *Jim Sledzik, WesternGeco*

combine to identify sedimentary features such as fluvial channels and deltaic fans. The WesternGeco Electromagnetics product line now offers magnetotelluric surveys to indicate the presence and thickness of subterranean resistive strata. Used sequentially, these technologies can greatly reduce exploration risk by identifying the most promising areas for detailed seismic exploration.

"High-resolution Q-Technology seismic is now uniquely enabling complex imaging solutions in extremely challenging geological environments. Rich/wide azimuth [RAZ/WAZ] and over/under [streamer] solutions will continue to propagate throughout the world as reservoirs become smaller and more complex. Finally, augmented by quality seismic data, interpretation of CSEM [controlled-source electromagnetic] surveys can reveal the presence and areal extent of hydrocarbon-bearing strata, further reducing exploration risk."

'Deep' and 'broad' advances

Leon Thomsen, current president of the Society of Exploration Geophysicists (SEG) and chief geophysicist for BP PLC, sees a two-pronged evolution of technology in the seismic business.

"Advances in geophysics and their practical applications are both 'deep' (meaning new extensions of existing ideas) and 'broad' (meaning new ideas beyond conventional seismic geophysics)," he says. "Examples of deep geophysical advances include wide-azimuth seismic, with a rich distribution of source/receiver azimuths; passive seismic (with no source at all); frequent time-lapse seismic, with permanent receivers enabling cheaper reshoots (done at intervals of every few weeks if necessary); cable-free land seismic using radio transmission of data to a doghouse; and 'surgical,' nonintrusive 3D surveys in urban areas such as the Barnett Shale play in the Dallas-Fort Worth metroplex."

He cites as examples of broad innovations in geophysics both nonseismic methods and integration with ideas outside of geophysics. The nonseismic methods include new developments in electromagnetic methods, which are able to sense hydrocarbon reservoirs at depth in favorable circumstances, and full-tensor gravity gradient and magnetic gradient methods that take advantage of declassified military technology. Ideas outside of geophysics include pattern recognition and new ideas from geology, sequence stratigraphy, petrophysics, and engineering.

"In deciding which of these technologies—both classical and modern—may be useful in any particular context, it is important for the operator to consider both the costs and the benefits of the technology," he says. "In this analysis, access to geophysical expertise is crucial, and SEG can help to provide it."

Reservoir characterization

Innovations in geophysical technology and advances in computing technology are enabling industry to learn more about the subsurface than ever before, spurring a quantum leap in reservoir characterization and monitoring, according to Fred Aminzadeh, SEG president-elect and president and CEO of dGB USA.

"We are able to see deep into the petroliferous basins of the world with a new ability to directly see reservoir rock and fluid flow properties resulting from new state-of-the-art full elastic wave seismic acquisition, allowing for better reservoir characterization and understanding," he adds.

More advanced pattern recognition techniques to relate the signature of geophysical measurements to reservoir properties are emerging, Aminzadeh notes. He speculates that it is conceivable that proper integration of data from different disciplines can identify details of the reservoirs with added certainty: "'Fingerprinting' of seismic data, or associating a given seismic character with the 'DNA' of a producing field or 'genetic building blocks' of known reservoir properties, may become a reality."

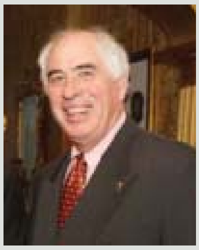
Aminzadeh contends that all of this effort has to be done with a better understanding of the physics of the earth, namely "the capture and interpretation of a full elastic inversion for various rock and fluid properties in reservoirs, along with the ability to see their behavior through visualization. Seeing 'fluids' flow will be the biggest accomplishment."

Such potential led Petroleum Geo-Services AS to recently commit to two third-generation Ramform vessels—due for delivery in the first quarters of 2008 and 2009—"because the industry has clearly embraced the need for large streamer counts," says Sverre Strandenes, PGS group president, data processing and technology.

"PGS firmly believes that we need to offer acquisition technology that can be tailored specifically towards each individual reservoir—that, in general, high-density 3D will provide more detail in a similar manner to increasing pixel density in digital cameras and deliver these configurations with the highest efficiency and reliability."

"Advances in geophysics and their practical applications are both 'deep' (meaning new extensions of existing ideas) and 'broad' (meaning new ideas beyond conventional seismic geophysics)."

— Leon Thomsen, SEG president



Over a period of several years, PGS has developed a radically new seismic streamer carrying both hydrophone and velocity sensors integrated into what it terms the "next-generation streamer," designed to enhance resolution, give better penetration, and improve efficiency.

Another area of reservoir characterization challenging geoscientists today is fracture modeling, notes Sledzik.

"Pivotal to the advancement of fracture modeling will be the ability to integrate various measurements at all scales and produce flow simulations that match the production history of the field," he says. "Recent developments using surface seismic data herald a step-change in our ability to condition and enhance well-based models, which historically have built fractures on theoretical and statistical methods in the interwell spaces.

"The integration of seismic into models built using discrete fracture network technology available in Petrel 2007—a technology built upon intellectual property licensed from Golder Associates—will significantly enhance the understanding of fracture characterization."

Production monitoring

Repeating seismic surveys over a producing field, when properly acquired and processed, can reveal differences in hydrocarbon saturation and pore pressure caused by production during the time interval between seismic reshoots, notes Thomsen. Such "4D differences" can help the operator to better understand subsurface details and thus help to properly plan the next well, he adds. The hitch: Such reshoots are costly, meaning they are acquired infrequently, and the careful processing required may consume many more months, thus limiting their value.

"These problems can be avoided in offshore fields if the seismic receivers are permanently installed on the seafloor and the 4D reshoots are conducted with a source boat only," Thomsen says. "The small size of the source boat means reshoots are cheap, and the permanently installed receivers mean that survey-related artifacts are greatly reduced. These factors work together to enable the frequency of reshoots to be reduced substantially."

He cites as an example eight reshoots conducted over 38 months at Valhall field in the Norwegian North Sea, resulting in an eight-frame "movie" of subsurface changes in seismic response.

"Careful economic analysis prior to launching the program is necessary to ensure that this early investment (to predict various aspects of reservoir performance and enable better reservoir monitoring and management) has a positive long-term payout."

PGS in 1997 started research on the potential use of fiber optic technology for permanent monitoring of producing reservoirs. There are several advantages with a fiber optic system compared with a conventional one, says Strandenes.

"A fiber optic system consists of passive optical cables and sensors with no in-sea electronics, utilizing proven optical components from the telecommunications industry," he points out. "Secondly, the fiber optic sensors are all designed to perform in deep water without the need for external pressure housing. In addition, a fiber optic system operates with no electrical power and with a lower weight, making it easier and safer to employ at the seabed. These advantages provide the foundation for making a system that is more reliable."

In 2006, PGS participated in the test of a fiber optic cable in the Gulf of Mexico.

"The test proved to be a success, and we are currently building a 12-km-long cable that will be deployed in 2007 on a producing field in deep water."

"We are able to see deep into the petroliferous basins of the world with a new ability to directly see reservoir rock and fluid flow properties resulting from new state-of-the-art full elastic wave seismic acquisition, allowing for better reservoir characterization and understanding."

Fred Aminzadeh, SEG president-elect

Borehole measurements/VSP

Borehole measurements allow new high-resolution seismic to see rock and fluid properties spatially in a 3D fashion where there has generally been little or no data, notes Aminzadeh.

"The economic impact of this type of reservoir scale measurements can be highly significant in boosting the NPV [net present value] as well as the production life of a producing reservoir," he says. "Various geophysical measurements at the borehole—including seismic-while-drilling and its integration with the more common logging techniques, reverse vertical

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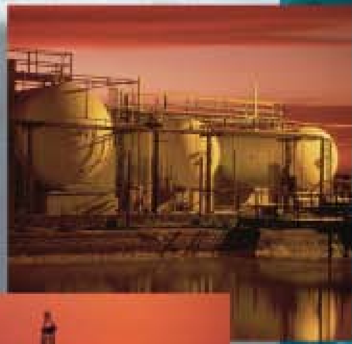

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Thumper trucks traverse desert train on behalf of Aramco Services Co., a unit of Saudi Aramco.
Photo courtesy of Aramco World/PADIA.

seismic profiles (where the seismic source is placed inside the well, and the measurements are made at the surface), borehole gravity, and well-to-well tomography—can find more widespread utilization, once their economic value in reducing drilling costs are understood and proven."

Aminzadeh contends that the growing popularity of horizontal/directional drilling will make both surface and borehole geophysical measurements an integral part of any drilling program.

Seismic data will realize their potential as quantitative oil field measurements when they tie with borehole data without being forced, says Sledzik: "With calibrated inversion of Q seismic data, rock and fluid properties can be propagated throughout the reservoir model in conjunction with geostatistics."

Wide azimuth/multi-azimuth

With the advent of RAZ/WAZ acquisition, industry is still in the early stages of understanding and realizing the full potential of the data, contends Sledzik.

"Key factors in maximizing the value of the seismic data will come through use of better well control (as more wells are drilled), WEM (wavefield extrapolation migration)-based multi-azimuth tomography, and full waveform inversion for better velocity models and salt geometry," he says. "RAZ/WAZ technology will also be complemented in many areas by the use of Multi-Measurement Constrained Imaging [MMCI], where we integrate marine magnetotelluric and gravity data to further enhance interpretation and modeling.

"In the Gulf of Mexico we are now using this to better define base-of-salt, which is critical to optimizing the subsalt image quality."

The greater operational complexity of WAZ multivessel surveys, frequently in congested areas, demands the highest standards in health, safety, and the environment, says Sledzik: "These survey fundamentals, combined with recording and source vessel synchronization, will rely upon the most experienced and highly trained personnel to ensure the safe and successful execution of WAZ surveys."

Because of their operational complexity, such surveys are also costly.

Consequently, detailed forward modeling should precede each project, Aminzadeh contends, noting that SEG is organizing a joint industry project dubbed SEAM (SEG Advanced Modeling Project) to collaborate on such complex modeling projects. SEG presentations at the 2007 Offshore Technology Conference in Houston demonstrated that full inversion studies of deepwater reservoirs are ready to begin, he adds.

Strandenes sees as the next major advances in RAZ/WAZ technology an increase in both the number of streamer and source vessels: "Also, wider towing spreads and utilizing data acquired on line turns could be possible future extensions.

"In addition to the acquisition techniques, we will see developments in the areas of wide-azimuth depth imaging, velocity depth model building, and improved efficiency in multiple removal methods."

Wireless recording

A new era of digital, full-wave seismic land surveys using wireless micro-electromechanical sensors is being implemented rapidly in the field, notes Thomsen.

"The jug hustler's task is considerably lightened, so to speak, if the miles of seismic cable in a 3D survey are replaced by radio transmission," he adds.

At the 2005 Society of Exploration Geophysicists convention, Input/Output Inc. (I/O) announced the world's first full-wave, cableless land acquisition system, FireFly, developed in partnership with BP and Apache Corp. Both operators committed funds to deploy the first system on their key E&D assets around the world, starting with BP's Wamsutter field in Wyoming.

"By leveraging wireless technology and eliminating the cables used in traditional land systems, FireFly reduces the cost, time, and safety risks involved in a survey by requiring fewer workers to lay out cables and by minimizing cable repairs," says Robert Peebler, president and CEO of I/O. "Reducing these acquisition costs enables more money to be spent on sensors and recording units, providing densely sampled, high-resolution subsurface data in return. At the same time, cable removal decreases environmental impact and allows companies to implement more flexible survey designs that are better aligned with their overall subsurface imaging objectives."

In late 2006, the first FireFly system was deployed at Wamsutter. The first Wamsutter survey involved recording about 7,200 shot points in a 28-square-mile survey area, according to Peebler. The acquisition crew averaged 700 shots per day with a dynamite energy source; peak production was 1,001 shots during a 6-hr period. Data processing has begun, and initial results appear promising, suggesting much higher-quality seismic images will be obtained.

"Over the next several years, both BP and Apache will be handing the initial FireFly system back and forth as they test how far they will be able to push the boundaries of land seismic imaging," Peebler adds.

Microseismic

Microseismic is emerging as a crucial tool in the development of unconventional gas resources, particularly in hydrofracturing tight gas sands and gas shales.

"A seismic truism is, 'One person's noise is another person's signal,'" notes Thomsen. "There are several ways to use seismic noise to advantage. Suppose, for instance, that the objective is to monitor a hydrofrac process by detecting and locating the microseismics triggered by the injection, without being tied to observations from only a nearby well.

"One way to do this is to lay out seismic receivers on the surface and simply turn them on, recording the microseismic events among the noise. By beam-forming the array in different directions (like shining a flashlight in different directions into a dark room) and stacking the data with a known velocity function, the microseismics can be located under favorable circumstances to reveal the regional extent of microseismicity caused by the hydrofrac operation."

Prestack depth imaging

The continued development of azimuthal processing technologies to extract the maximum value from full azimuth and WAZ acquisition solutions will further enhance depth imaging, says Sledzik.

"In areas of the world with challenging salt and basalt imaging challenges, we expect to see increased deployment of Q-Marine technology to facilitate a combination of [RAZ/WAZ] solutions with over/under streamers to significantly improve the imaging of subsalt and sub-basalt geology.

"In many cases, we also expect to use [MMCI], which brings together the benefits of the best seismic with marine magnetotellurics and gravity data in one integrated model. This will allow us to reduce uncertainty and significantly improve the depth imaged data.

"Finally the enhanced integrity of the data achieved with MMCI and the lower frequencies obtained through deployment of the Q-Marine technology will enable the capture of low frequencies, which will greatly improve the potential for full waveform inversion."

PGS believes that pre-stack imaging portfolios must have flexibility in accuracy vs. cost for the various imaging challenges experienced, contends Strandenes.

"As a consequence, we have developed a broad portfolio of velocity depth model building tools and depth migration algorithms," he says. "Current migration methods have limitations in the imaging of steeply dipping reflectors such as those found on salt flanks.

"Reverse time migration (RTM) overcomes these constraints, enabling structures with dips greater than 90° to be imaged. An RTM was released in 2006 by PGS, thus providing a solution to the two-way wave equation, capable of accurate imaging in the most challenging geology. The PGS solution is isotropic now, but the natural extension is to also include anisotropy and more accurate true amplitude solutions."

Strandenes believes that seismic waveform analysis—instead of the current wave equation or travel time-based tomography methods could be the next game-changing seismic technology for the depth velocity model update.

"In Waveform Tomography, the input data consist of the seismic waveforms as opposed to the picked travel times, and the underlying numerical method is based on the full wave equation," he notes. "However, more fundamental research is required to deliver state-of-the art industrial tools."

Wide-azimuth surveys are delivering data results with unprecedented resolution. Shown is the Geo Challenger, the new flagship of CGG-Veritas's seismic fleet. Launched in summer 2006, the new 3D/4D vessel was converted to 12 tow-point capacity and equipped with 80 km of new Sercel Sentinel solid streamers. It is the first seismic vessel in the world to operate with this new cutting-edge solid streamer technology. *Photo courtesy of CGG-Veritas.*

As more complex subsurface structures or those associated with poor data quality (e.g., deepwater or subsalt) become E&P targets for many producers, more accurate, faster, and more cost-effective methods continue to be in high demand, notes Aminzadeh.

"While advances in hardware (faster and cheaper computers) are expected to play a key role, more efficient software approaches to reduce the cycle time (especially the human-intensive component) will be important," he says. "For example, a more interactive velocity model building workflow and recursive algorithms (e.g., incorporating 'implicit representation') are expected to make a major impact."

Software

The nature of software development and the way software is licensed for commercial use is also going through a major revolution, claims Aminzadeh.

Among the new trends he cites are the ability to use the software as a commodity (pay per use), access software through the internet, and use a multitude of software packages from different vendors on a single platform. Aminzadeh expects open source software to become increasingly common.

"These trends are unstoppable, but they are slowed down by several factors," he says. "First, there is the demographic distribution of our profession. People of our generation are overrepresented. In general, this generation takes the decisions regarding new software tools, while it is less willing to learn new techniques than younger generations. Secondly, most professionals are under extreme time pressure to perform only the basic tasks, leaving no time for introducing new technology. Lastly, in large companies, standardization is considered more important than innovation. IT departments rule instead of serving."

Seismic analysis/interpretation

Advances in pattern recognition and other nontraditional analysis are helping to push the boundaries of seismic interpretation.

"Normally, geophysicists look for anomalies within otherwise regular patterns," says Aminzadeh. "In many situations, conventional statistical means are inadequate to tackle practical problems, and nontraditional methods such as neural networks, fuzzy logic, complexity theory, genetic algorithms, chaos theory, and fingerprinting are employed." These tools have proven useful in many complex geologic settings, such as fractured reservoirs, where simplifying assumptions such as homogenous medium and "convolutional models" are not valid, he points out.

"Fuzzy logic and other nonlinear methods can describe shapes and structures with realistic geologic complexity," says Aminzadeh. "These techniques can push the boundaries of seismic resolution, allowing smaller-scale anomalies to be characterized."

The SEG president-elect cites a paper presented at the 2006 SEG Annual Meeting that detailed how a neural network was used in conjunction with fuzzy logic to high-grade prospects containing hydrocarbon-saturated reservoirs.

"This was accomplished by using fuzzy logic to formulate general rules of thumb, derived from rock physics data and interpreter's knowledge and experience," he says. "Integrating such linguistic rules with a neural network ranking (of the most relevant attributes for prospect risking) improves the process when compared to conventional 'thresholding' methods."]