Hart's
Petroleum Engineer®
INTERNATIONAL

June 1998

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FOCUS ON RUSSIA

WEATHERFORD INTERNATIONAL, LLC, et al.

EXHIBIT 1025

WEATHERFORD INTERNATIONAL, LLC, et al.
v.
PACKERS PLUS ENERGY SERVICES, INC.

Volume 71, Number 6 June 1998

Hart's Petroleum Engineer® INTERNATIONAL

CONTENTS

NEXT MONTH

Petroleum Engineer International's July issue will spotlight coiled tubing and multiphase metering. The monthly geographical focus will feature Latin America.

ON THE COVER

Shell U.K. Exploration and Production's Tern Platform in the North Sea. Photo courtesy of MDC Technology Ltd.

Jeanne M. Perdue, Technology Editor

➤CASPIAN SEA

Is The Caspian A Sea Or A Lake?

Preliminary agreements have been reached concerning the division of the Caspian Sea, which had been the subject of debate about whether it should be considered a lake or sea. If it is determined to be a lake, then all countries will share resources equally. However, it seems more likely to be declared a sea, in which case it will be divided up into offshore zones.

Kazakstan's View

Kanat Saudabayev, Kazakstan's ambassador to London, said the deal to divide the sea based on the principle of equal distance could be signed by the end of May as a result of recent negotiations among the Caspian's five littoral states. "Kazakstan, Azerbaijan and Turkmenistan have already begun production and have begun working on their own sectors of the Caspian, so we can say that, *de facto*, the Caspian has been divided," Saudabayev said. Only ratification of the agreement is required. Separately, President Nursultan Nazarbayev said Kazakstan is suspending further privatization contracts and outside investment to conserve oil and gas resources for future generations. "We have 72% of our economy privatized and many parts of it are based on oil and gas contracts. For this generation and the next, we have completed all contracts."

Iran's View

Iran would oppose any deals for "unilateral" exploitation of the Caspian Sea, according to a Foreign Ministry spokesman. Mahmoud Mohammadi was quoted by Tehran radio as saying, "Any understanding on principles which would eventually lead to a unilateral exploitation of Caspian Sea... would be unacceptable to littoral states, particularly Iran, and would be rejected." Deputy Oil Minister Ali Majedi said, "We have squandered many of our interests in the exploration and exploitation of the Caspian Sea by not taking decisions in time...and we will lose more if we fail to act soon."

Azerbaijan's View

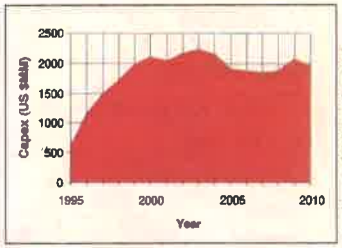
Azerbaijan International Operating Co. (AIOC) reported that the Chirag 1 production platform is now producing 40,000 b/d of oil from three wells. Ultimately, the consortium plans to drill a total of 24 wells from the Chirag 1 platform to exploit the Azeri, Chirag and Guneshli fields, with production of 110,000 b/d expected. Separately, MAI Consultants were commissioned by SOCAR to study the feasibility of rejuvenating several Caspian Sea fields containing 450 million bbl of oil and 3.4 tcf of gas. SOCAR is preparing information packages and will invite tender offers on these 20-year-old fields later this year.

Turkmenistan's View

The government of Turkmenistan and Western Atlas have signed a memorandum of cooperation to expand development of the country's oil and gas sector. A national seismic database will be created and technical initiatives will improve the country's exploration and development industry. Western Atlas has just completed an offshore seismic shoot in the Turkmenistan sector of the Caspian Sea, and evaluation of potential hydrocarbon reservoirs by international players is now underway. Western Atlas is currently conducting another seismic survey in the shallow water transition zone of the Caspian's Turkmen Shelf.

Russia's View

Until April, Russia had favored the lake designation, but now is prepared to divide the Caspian into national sectors. The Caspian Pipeline Consortium oil pipeline from Kazakstan's Tengiz field to Russia's Black Sea port of Novorossisk will be finished by the end of 2001, according to Vagit Alekperov, head of Lukoil. The Russian giant and Chevron have signed an agreement on a final timetable for the $4.5 billion project. Acting first deputy prime minister Boris Nemtsov has requested that land allocation be completed by June.



Compliments of MAI Consultants Ltd.

Caspian CAPEX Projection

U.S. View

At Rice University in Houston, a new study was released on the political, economic and cultural aspects of Caspian Sea hydrocarbon production. Director Edward Djerejian said, "While there is no question that Caspian Sea resources are significant, there is a need for perspective." The Caspian holds only 2.7% of the world's oil, compared to the Middle East with 55%. Half is in Kazakstan, while Turkmenistan has the lion's share of the Caspian's gas reserves; both countries are landlocked. The study recommended a single pipeline to bring these hydrocarbons to distant markets economically."

➤OIL PRICES

OPEC Ponders Further Production Cuts

OPEC ministers will meet in Vienna on June 24 to evaluate further cuts in oil production because oil prices failed to increase after signing the production agreement in Riyadh in March. The Economist Intelligence Unit calculated that production will be down to 28.12 million b/d from 28.82 million b/d before the deal. Thus, spot prices should increase to $16/bbl by the end of the year. However, OPEC countries will still be producing 630,000 b/d above the agreed quota, resulting in a global surplus of 500,000 b/d and prices about 18% below 1997 levels.

Sheikh Zaki Yamani, chairman for the Centre for Global Energy Studies (CGES), said oil prices are likely to remain weak—around $13/bbl—for the next 5 years or so. At a CGES Asian oil conference, Yamani said, "OPEC continues to prefer to fight fires as and when they flare up rather than preventing them from occurring in the first place." He maintained that OPEC had never prepared itself adequately for Iraq's re-entry to the oil market and "now that the UN seems happy to allow Iraq to export as much oil as it physically can," OPEC still has no urgent plan to accommodate the additional oil.

OPEC President Obeid bin Saif al-Nasseri, oil minister of the United Arabian Emirates, said further OPEC cuts would depend upon participation by non-OPEC countries.

Russia. Despite earlier reluctance, Russia has decided to cut back on crude oil exports by 61,000 b/d—about 2.3% of Russia's production—but has not stated when this would begin.

China. China National Petroleum Corp. has reduced production by 5%, or about 150,000 b/d, since April 1, according to Reuters. The country's onshore production fell by 590,000 tonnes during the first quarter of 1998, according to China Petroleum News. Xinjiang oil fields shipped only 490,000 tonnes of crude in February, 100,000 bbl less than the official plan. The Daqing, Jilin and Tarim field have shut down more than 1,000 wells, slashing output by more than 10,000 tonnes/day.

➤NORWEGIAN POLICY

Norway Holds Back On Production, Investments

Norway will decrease oil production by 100,000 b/d in 1998, said Haakon Steinar Gill, Norway's deputy minister of petroleum and energy at an Offshore Technology Conference breakfast. He said beginning May 1 and continuing to the end of the year, 36 Norwegian fields would reduce output by 3% compared to the expected 1998 production curves, which would result in total output about equal to 1997. This action was taken independently of OPEC and other oil-producing countries.

"We make our decisions based on our own deliberations," Gill said. Gas and condensate fields that produce oil as a byproduct will be exempt, as will the Statfjord and Murchison fields, because they straddle both Norwegian and UK waters.

Oil production is not the only thing slowing down in Norway. The Norwegian Department for Oil and Energy (DOE) recently issued a White Paper to the Storting (parliament) concerning postponement of investments in the petroleum sector to avoid overstimulating the economy. Authorities will approve all projects in the usual way, but start-up investments for all discoveries currently under evaluation will be delayed 1 year, but not beyond July 1, 1999.

Haakon Steinar Gill

➤GREEN TAXES

The Norwegian government has also proposed a set of "green taxes," which include NOK 100 per tonne of CO_2 emissions and NOK 3 per kg of SO_2 emissions. Such a move would decrease Norway's greenhouse gas emissions by 5.6 million to 7.1 million tonnes of CO_2 equivalents in 2-5 years, according to government estimates.

The three largest opposition parties in the Storting—Labour, the Liberals and the Conservatives—are all opposed to these proposed green taxes. Labour might support CO_2 taxes if the law allows trading of CO_2 quotas—a policy favored by Statoil. The Conservatives said CO_2 taxes would have a negative impact on Norway's competitive power, since other countries do not have similar taxes. The Liberals claimed CO_2 taxes would only hurt the industry and have little or no effect on the environment.

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Integrating People, Process And Technology

by Robert P. Peebler, president and CEO of Landmark Graphics Corp.

Global oil and gas companies today are seeking the Holy Grail of enterprise-wide integration—the ability to access the collective knowledge of the organization to make fast, effective business decisions. In this environment, it is easy to become hypnotized by the seemingly limitless potential of information technology. But technology is only part of the ultimate integrated solution.

Integration is as much about people and process as it is about technology. Yet few senior executives have focused on all three issues. As a result, most E&P organizations have only "islands of integration." Despite advanced hardware, shared databases and integrated applications, technical professionals keep running into social and organizational bottlenecks. If they cannot address these "soft" issues, oil companies will never achieve the productivity gains they expect from information technology.

The center of gravity in a company must shift from function to process. The traditional organization chart represents a purely functional view of a company. It illustrates reporting relationships among internal functions, but fails to indicate how or why work actually gets done. People manage the boxes on the organization chart, but not the "white spaces" between them. Managing the business as a system requires three components not depicted on a typical organization chart:

- Work processes that flow horizontally across the functions.
- Outside partners and suppliers who contribute to the processes.
- Customers who are the organization's reason for being.

No permanent productivity improvement will occur without serious redesign of processes. They are especially critical in this era of alliances and virtual corporations. Well-defined processes unleash the creativity of individuals and teams.

In most oil and gas companies, asset teams are rapidly becoming the norm. But members often experience conflict between the team's goals and their own professional interests. Some companies forget the basic truth that, while at times we may act as part of a team, we are always individuals. And individuals in business are always part of a larger system, regardless if they are part of a "team."

With regard to teams, too often people are thrown into a room, called a team, and told to "figure it out." In most cases, that won't work. People need clear expectations about what to produce and when, and an understanding of how to do the work. Besides the intellectual and physical capacity to perform required tasks, they must have the proper tools and resources (including information technology). When the team involves internal groups, external partners and service companies, a cross-functional process map is also essential. Finally, consequences that support the team process must be found. Many organizations talk teams, but continue to reward individual performance.

Bob Peebler

Information technology can enable teams and individuals to implement more effective business processes. Yet so much available technology and information can create chaos. On the Web, search engines provide ways of creating processes that enable people to manage millions of potential interactions.

As oil and gas enterprises grow increasingly complex, process definition must precede the application of information technology. A well-defined process acts as a "search engine." It identifies the decisions that need to be made, the best people to make them, and the tools and data required. Processes provide the context for converting data into information, information into knowledge, and knowledge into wise business ventures.

Technology alone cannot achieve that. Data and information can be stored on a server but knowledge resides in people's heads. In a true learning organization, knowledge is never static. Information technology's proper role is to enable creative people to share knowledge and collaborate more effectively in those processes that deliver ultimate value to the marketplace. ●

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➤SOFTWARE

3-D Well-Planning Software Solves Complex Problems

Reservoir development via multilaterals and extended-reach horizontal drainholes presents complex well-trajectory problems to the operator. Two new software programs from Sperry-Sun offer true integration of 3-D models into the directional well planning process. Called DrillQuest™ and DrillQuest Visualizer™, the programs are designed to simplify the often-complicated task of planning and drilling multiple directional wells.

Previously, well-planning and 3-D visualization software resided on different platforms and were used by different technical groups. Intercommunication between geophysicists, geologists and reservoir engineers is greatly facilitated when data can be processed in a common operating environment capable of importing geological and geophysical information from the operating company's earth model. During actual drilling operations, the common system makes communication with drilling engineers and service company personnel straightforward and efficient.

DrillQuest incorporates trajectory planning, torque and drag calculations, hydraulics and BHA analysis. Wizards help with target design, casing design, anti-collision and proximity analyses. The DrillQuest Visualizer allows the completed well plan to be viewed in 3-D space along with the reservoir model.

DrillQuest visualization software works on a desktop environment, and allows easy importation of horizons, faults and geophysical data. Historical data can be imported so each proposed well can be evaluated in context with previously-drilled wells. The 3-D plots can be rotated so the entire well-design team can fully visualize how the completed well will drain the reservoir.

The desktop environment allows easy portability of the well plan to the rig to facilitate onsite communication and updates during the drilling process.

➤SOFTWARE

Integrated Software Improves Productivity

Long associated with commercial database and archival systems, Petroleum Information/Dwights LLC has introduced PowerTools™, a Windows-based reservoir analysis and economic software package. By integrating decline curves, pressure curves, volumetrics, economics and the map in one application, PowerTools allows users to perform required analyses with greater speed and flexibility.

A new interface has been introduced that permits users to begin working with the application and performing real work within minutes. The software is very fast. For example, production and reservoir engineers can grab 100 wells off a production CD, load and process all calculations, then post values to the map along with all culture, survey and well data in less than six minutes. Graphics are easy to read and understand, and judicious use of colors facilitates use of the maps to analyze trends.

Lease economics are integrated with all calculations and can be displayed in the tabular form preferred by financial analysts. Users can define costs, oil prices, escalations and interest rates, and can output payouts, rates of return, ROI and detailed net present value estimates.

A second integration links the project tree and the map. Wells selected from the map are reflected on the project tree and vice versa. This allows the user to combine text and spatial selections, and post all the data fields and calculations to the map in the form of labels, bubbles and contours. The result is improved productivity and synergy—more can be accomplished with the combination than with the two databases used separately.

➤**SOFTWARE**

New Program Lets Users "See" Their Mud At Work

Engineers who have longed for a chance to see what their drilling fluid does at the toolface will want to check out a new Windows-based software application from M-I LLC. The program, called Virtual Hydraulics®, simulates fluid rheology, hydraulics and density under downhole conditions. Primarily for use in predicting the behavior of high-performance synthetic and oil-based drilling fluids in HTHP situations, the program is also useful in extended reach or other applications where critical control of mud properties is essential. It can be used in well-planning, for optimization and trouble-shooting during drilling and for post-job analysis.

When real-time pressure-while-drilling information is not transmitted by the MWD/LWD tools, the simulation technology can be used in calculations aimed at minimizing excessive surge pressures while tripping.

The program evolved from two concepts. The rheology section takes full advantage of available well and mud data from the specific fluid in use and combines it into data cubes which use 3-D interpolation to provide maximum accuracy for rheological predictions. The second, for hydraulics, subdivides the annulus and drill string into hundreds of short segments, each described by its own set of parameters. Interaction between segments is used to improve realism, and interpretive (fuzzy) logic models parameters when adequate hard data are unavailable. Special concerns addressed by the fuzzy logic solutions include hole cleaning, barite sag and stuck pipe potential.

In addition to the 3-D data cubes and interpretive logic techniques, specific innovations appearing in the new software include finite difference analysis methods to evaluate hydraulics, rheology and density and "snapshot" views of dynamic downhole conditions at specific points in time.

In the field, results have consistently matched measured data. In a recent Gulf of Mexico well, Virtual Hydraulics was used to predict equivalent circulating density (ECD), static fluid density and frictional pressure losses, as well as make pump pressure calculations. The actual ECD measurement, as verified by a pressure-while-drilling tool, was within 0.07 ppg of the estimated value.

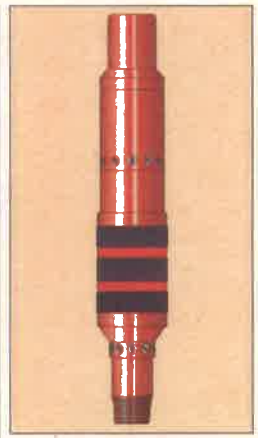
➤**PACKERS**

Reliable Zone Isolation In Horizontal Open Holes

Many operators with long histories of success with pressure-set openhole packers in vertical wells felt the need to convert to inflatables when wells turned horizontal. From Canada comes an innovative new openhole pressure-set packer especially designed for horizontal wells. Called Wizard™ II, from Dresser Oil Tools' Guiberson Division, the packer can be run on casing sizes ranging from 4½-in. (3⅞-in. openhole) to 9⅝-in. (8½-in. openhole), and tubing ranging from 2⅜-in. to 7-in. The tool is set by applying pressure to the tubing or liner, and the initiating pressure can be adjusted so that multiple packers can be selectively set. The packing element is stroked by an internal hydraulic cylinder. After it is set, the packoff is locked in place until it is released by shearing.

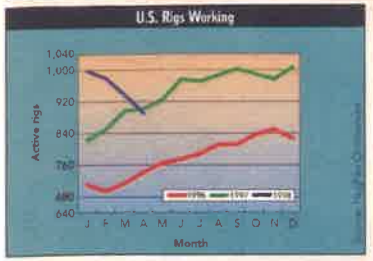
An innovative ramp-style system provides a large extrusion ratio for element expansion, without compromising ruggedness or reliability. According to the manufacturer, element life expectancy exceeds 20 years and can be configured for high temperature or sour service. Applications include horizontal well segmentation, water or gas shutoff, stimulation or service tool work in openhole and production testing of horizontal well segments.

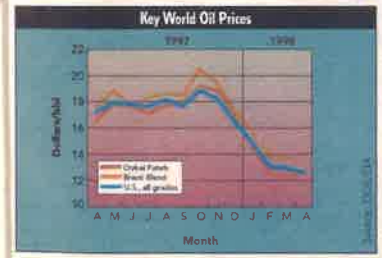
Recently in Canada, Wizard II packers on tubing were used to replace a cemented liner. Operators have reported failure rates with inflatable openhole packers up to 75% during 1 year. Post-failure analysis identified the inflatable element as the weak link. It was neither rugged nor durable enough for prolonged use in horizontal applications and the smallest leak rendered it useless. The greatest risk to an inflatable exists when it is deflated for moving. Often the element does not deflate completely, leaving a slightly oversized profile to snag or tear as the work string is pulled.



The Wizard II Openhole Pressure-Set Packer is designed for horizontal wells.

STATISTICS





U.S. Dry Natural Gas Production

Component, bcf per month	April 1998	March 1998*	April 1997*
Total dry gas production	1,566	1,848	1,550
Withdrawals from storage	-187	255	-58
Supplemental gaseous fuels	10	10	9
Imports	245	257	221
Balancing item	174	-16	63
Total gas supply	1,808	2,194	1,785

Source: DOE/EIA *Revised

U.S. Oil Production

Thousand barrels per day	April 1998[a]	March 1998*	April 1997*
Crude oil and lease condensate			
Alabama	38	42	42
Alaska	1,203	1,224	1,380
Arkansas	22	22	21
California	929	925	912
Colorado	65	65	64
Florida	18	17	18
Illinois	45	48	42
Kansas	116	116	116
Kentucky	9	9	9
Louisiana	1,382	1,350	1,219
Michigan	28	28	28
Mississippi	54	60	53
Montana	41	44	42
Nebraska	10	10	9
New Mexico	178	178	170
North Dakota	102	99	89
Ohio	21	22	24
Oklahoma	224	223	227
Texas	1,619	1,619	1,590
Utah	52	52	52
Wyoming	205	199	176
Others	22	22	22
Total supply	6,365	6,351	6,305

Source: API *Revised [a]Latest month estimated

World Oil Production

Million barrels per day	April 1998	March 1998*	April 1997*
OPEC			
Saudi Arabia	8.17	8.35	7.90
Iran	3.49	3.60	3.70
Venezuela	3.17	3.37	3.15
United Arab Emirate	2.32	2.44	2.29
Kuwait	1.82	1.93	1.80
Others	8.99	9.15	6.91
NGLs and condensate	2.88	2.86	2.90
Subtotal	30.84	31.70	28.65
OECD[1]			
U.S.	8.58	8.48	8.49
Canada	2.50	2.60	2.68
UK	2.88	2.89	2.98
Norway	3.38	3.40	3.41
Others	1.36	1.39	1.40
Subtotal	18.70	18.76	18.76
NON-OECD			
Former USSR	7.24	7.29	6.96
China	3.16	3.15	3.28
Europe (others)	0.22	0.22	0.29
Mexico	3.48	3.54	3.42
Latin America (others)	3.62	3.62	3.44
Asia	2.14	2.12	2.06
Middle East	1.88	1.90	1.97
Africa	2.78	2.86	2.84
Subtotal	24.52	24.70	24.26
Processing gains	1.64	1.64	1.56
Total production	75.70	76.80	72.23

Sources: EIA Monthly Oil Market Report *Revised [1]Includes Baltic

Summary of Current Offshore Rig Economics (S.C.O.R.E.)*

	April 1998	March 1998*	Monthly % change	Yearago % change	5 years ago % change
By Region					
Gulf of Mexico	65.72	65.72	0.0	12.0	83.0
North Sea	82.90	83.34	-0.5	22.0	172.3
West Africa	73.76	74.14	-0.5	10.4	103.1
Southeast Asia	67.60	67.18	0.6	12.7	89.2
Worldwide	72.66	72.61	0.1	15.6	117.9
By Type					
Jackups	81.12	81.57	-0.6	19.6	103.9
Semisubmersibles	65.34	64.65	1.1	11.5	155.1

*S.C.O.R.E. reflects operating day rates as a percent of the worldwide assumed to justify building new rigs.
Source: Global Marine Inc. *Revised

1998 MERITORIOUS ENGINEERING AWARD WINNERS

PEI Presents 1998 MEA Awards

Petroleum Engineer International presented plaques to the winners of its 1998 Meritorious Engineering Award winners at the Offshore Technology Conference in Houston on May 4, 1998. The award honors engineers from every segment of the industry for developing new products and technologies that demonstrate innovation in concept, design and application as well as the potential to solve costly problems and improve efficiency.

An entry form for the 1998 Meritorious Engineering Awards is included on p. 22. Photography by Fred Keinz.

WINNERS

Auger Separator For Downhole Or Surface Gas/Liquid Separation
ARCO and Krebs Petroleum Technologies

CLINCHER Lockjaw Tong And Backup System With Low Friction Technology And Grit-Faced Dies
Superior Manufacturing and Hydraulics Inc.

CT Riser For Subsea Well Intervention
XL Technology

DeepWater Flo-Stop 3000
Halliburton Energy Services Inc.

Galileo Reeled Technology System For Re-Entry And Slimhole Drilling
Baker Hughes INTEQ

GeoMechanics Computerized Drilling Analysis System
Security DBS

Multilateral Root System
Baker Oil Tools

RWD (Ream While Drilling) System
Hughes Christensen

Stim-Gun Assembly
Owen Oil Tools Inc., Marathon Oil Co., Computalog Inc., HTH Technical Services Inc. and Instrumentation and Engineering Services Inc.

Ultrasonic Processor
The Expro Group

Vision 475
Anadrill Schlumberger

Wireline Conveyed Downhole Tiltmeter Fracture Mapping Technology
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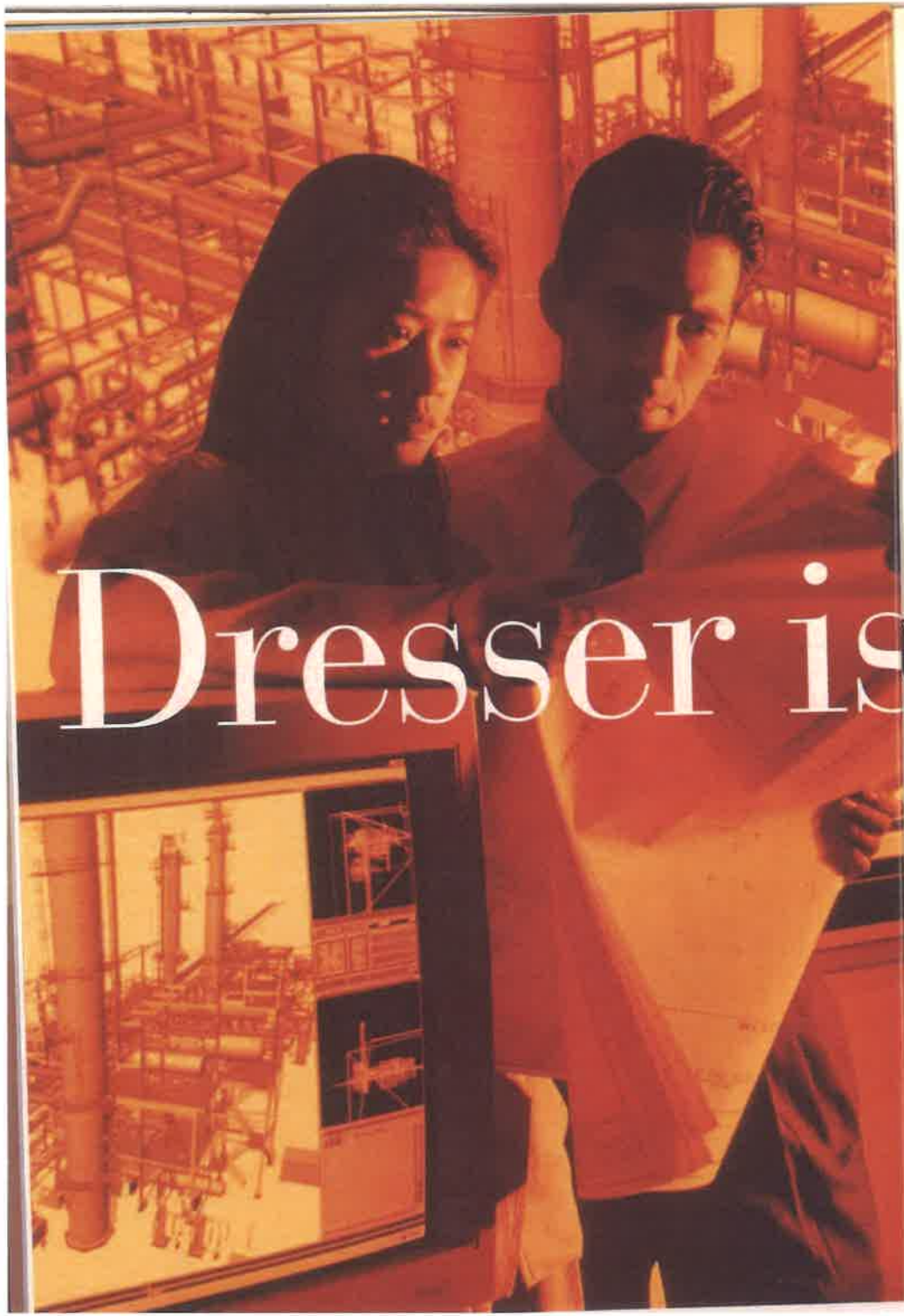
Jerome J. Schubert, PE
Texas A&M University

Robert W. Sears
RWS Petroleum Consultants

Scott Sigurdson
ARCO E&P Technology

James J. Smolen
Smolen Associates

Robert Urbanowski
Grey Wolf Drilling Co.



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Circle 112

MERITORIOUS ENGINEERING AWARDS

Arco and Krebs Petroleum won an MEA award for the Auger Separator for Downhole or Surface Gas/Liquid Separation. Present for the ceremony were (l-r) Jim Mitchell, Jim Eastlack, Jean Weingarten, John Ditrie, Dick Ghiselin, *PEI* publisher; Hank Rawlins (kneeling).

Superior Manufacturing & Hydraulics won a Meritorious Engineering Award for its CLINCHER Lockjaw Tong and Backup System With Low Friction Technology and Grit-Faced Dies. Attending the presentation were (l-r) Matson Yandle, Mike Coates, David Buck, *PEI* Publisher Dick Ghiselin, Dan Bangert, Scott Latiolais and Ning Malathong.

Present for XL Technology's award ceremony were Dan Turner, *PEI* Publisher Dick Ghiselin, Philip Head, Rory Cooper. The company won the award for its CT Riser For Subsea Well Intervention.

Present for Halliburton Energy Services' award ceremony for its DeepWater Flo-Stop 3000 were Gary Keene, Kamyar Tehranchi, B.N. Murali, James E. Griffith, Steve Batchelor, Joseph Faul and Dick Ghiselin, *PEI* publisher.

Attending Baker Hughes INTEQ's MEA ceremony for the Galileo Reeled Technology System for Re-Entry and slimhole drilling are (l-r) Dick Ghiselin, *PEI* publisher; Richard W. Griffhorn, Pete Fontana, Bob Ewen, Glenn Leroux and Tim Probert.

(L-r) Dick Ghiselin, *PEI* publisher; Kelley Murrell, Lee Smith, Bill Goldman, Oliver Matthews, Kambiz Arab attend the MEA presentation for Security DBS' GeoMechanics Computerized Drilling Analysis System.

PRESENTATION PHOTOS

Present for Baker Oil Tools' Multilateral Root System presentation are (front row) Ed Howell, Kenny Smith, Gerald Lynde, Dick Ghiselin (back row) Jeff Lembcke, Doug Murray, John Johnson, Matthew Jabs and Jim Burtner. Not pictured Roy Swanson and Jeff Toulouse.

(L-r) Dick Ghiselin, *PEI* publisher, presented an award to Mark Kizziar, Bart McDonald, Cary Maurstad, Michael Doster, D.J. "Doug" Wall, and Ted Zaleski for Hughes Christensen's RWD (Ream While Drilling) System.

Doug Robinson, Computalog; Phil M. Snider, Marathon Oil Co.; David S. Wesson, P.E. Owen Oil Tools Inc.; Joseph Haney, HTH Technical Services Inc.; and Daniel J. Abshire, Instrumentation & Engineering Services accept the award from *PEI* Publisher Dick Ghiselin (left) for the Stim-Gun Assembly. The product was a joint entry by Owen Oil Tools, Marathon Oil Co., Computalog, HTH Technical Services, Instrumentation and Engineering Services.

Graeme Coutts and R.V. Walsh accept an award for The Expro Group's Ultrasonic Processor from *PEI* Publisher Dick Ghiselin.

Attending the presentation for Schlumberger Anadrill's Vision475 award were Jacques Holenka, Pascal Panetta, Stephen D. Bonner, David White, *PEI* Publisher Dick Ghiselin and Kyel Hodenfield.

PEI Publisher Dick Ghiselin (left) presents Chris Wright (middle), and Eric Davis a MEA award for Pinnacle Technologies' Wireline Conveyed Downhole Tiltmeter Fracture Mapping Technology.

A Baby Brother For The Seven Sisters?

By privatizing, consolidating and forming joint ventures with Western oil companies, the oil industry of the former Soviet Union is modernizing and thriving.

by **M. Liliana Riahi**, International Editor

For decades, the former Soviet Union produced more oil than any other country in the world, far outstripping its closest rivals, Saudi Arabia and the United States. By 1990, crippled by falling government investment and the disintegration of the planned economy, the Soviet oil industry was crumbling. Deputy Minister of Oil Production Vagit Alekperov, knowing that the old Soviet system was doomed, proposed breaking up the oil industry into about 12 integrated companies. However, in government circles, this was perceived as being an obvious attempt to destroy centralized planning. Alekperov was on the verge of losing his job when his superior, the minister of oil production, became embroiled in the failed coup against Soviet President Mikhail Gorbachev.

Suddenly, Alekperov found himself as the acting oil minister and, for the last several months of the Soviet Union's existence, with the old command structure in collapse, he was virtually in complete control of the oil industry. At stake, in the former Soviet Union, were 57 billion bbl of oil reserves already mapped out and, possibly, double that if the vast expanse of eastern Siberia is included, much of which has yet to be prospected. "It's the last frontier for an oilman to find major new reserves," said T. Don Stacy, president of Amoco's Eurasian subsidiary.

Alekperov moved quickly. First, he gave the country's oil assets to the Russian Oil Co. (Rosneft). Then, gathering the country's brightest engineers and three major Western Siberian production units—considered to be among the best oil properties in Russia—Alekperov established Lukoil, one of the eight largest oil companies in the world, with proven reserves of more than 10 billion bbl.

Lukoil

Alekperov has emerged as the power broker in nearly every large deal involving oil anywhere in the former Soviet Union. In 1993, Lukoil became Russia's first vertically integrated well-to-gas-pump oil company. To that end, the company acquired refineries and negotiated franchise agreements to operate a chain of gasoline stations using the Lukoil trademark throughout Russia and other parts of the world, including the United States. The first Lukoil service station in the United States opened in Altavista, Va., in July 1997. Successful cooperation with supermarkets will allow Lukoil to create a network of service stations throughout North America.

As an integrated company, Lukoil offered its first shares to investors in 1994. The Russian government's long-term share is about 5%; America's Atlantic Richfield Co. (ARCO), Credit Suisse First Boston and various hedge funds have about 20%; foreign investors have 15%; Lukoil's pension fund and company satellites such as Imperial Bank and Nikoil have 29%. The remaining 31% is divided among Alekperov, senior managers and workers. In 1994, Lukoil produced 416 million bbl of oil and pumped more crude oil than any other company in the world, except Royal Dutch/Shell, Exxon and British Petroleum.

LukArco. In February 1997, Lukoil and Los Angeles-based ARCO formed a joint venture, named LukArco, to develop oil and gas fields in Russia, the Commonwealth of Independent States and countries outside the former Soviet Union. ARCO agreed to open a credit line for $4.5 billion to finance LukArco's exploration and production programs. Investments totaled about $5 billion. The agreement established how profits would be divided and how financing would provide for future projects. Lukoil owns 54% of LukArco and ARCO holds 46%.

ARCO, the seventh largest American energy producer, currently owns 7.99% of Lukoil's shares, which it acquired through convertible bonds for $340 million, making this the biggest officially declared shareholding by a foreign investor in a Russian oil company to date. In 1996, Lukoil posted a net profit of more than $600 million and extracted 58.3 million tons of oil or 1.24 million b/d.

Sidanco. With the support of then Russian Prime Minister Viktor Chernomyrdin, negotiations were initiated for Lukoil to

merge with the Siberia Far East Petroleum Co. (Sidanco), rated the third largest oil and gas company in Russia in terms of output. The prime minister's financial policy was based on amalgamating Russian companies into powerful units with greater reserves and production ratios and with dedicated managements operating at acceptable international standards to instill confidence in international investors and become independent of unwelcome pressure resulting from foreign borrowing.

In November 1997, British Petroleum (BP) announced that it would form a strategic partnership with Sidanco, in which it planned to take a 10% stake. Over the long term, BP would provide the two companies with a strategic base from which to develop a major joint exploration and production business in East and West Siberia. In addition, BP would acquire 45% of Sidanco's interest in the Rusia Co., an Irkustsk-based company with major oil and gas discoveries in East Siberia in which Sidanco has a 60% stake. To earn this interest, BP agreed to pay $172 million of the costs of appraising Rusia's fields and to set up a joint venture to develop and operate the Rusia Co. discoveries along with any new assets and exploration acreage they may acquire in the region.

Caspian Basin

The Caspian Basin, where Europe, Central Asia, and the Middle East meet, is current hot spot in the oil industry. The region's energy reserves are worth trillions of dollars and developing them will cost an estimated $50 billion or more during the next decade. Azerbaijan, Kazakstan, and Turkmenistan together possess an estimated 100 billion to 170 billion bbl in producible reserves, making the Caspian the world's richest new energy region and the third biggest in reserves after the Persian Gulf and Siberia.

There has been bitter wrangling over who owns what resources in the Caspian Sea. The Caspian has been touted as the world's next great oil province, and although its reserves and potential are not in doubt, seemingly endless political and geographical problems have delayed progress in exploiting its resources.

The Caspian, surrounded by Russia, Azerbaijan, Iran, Turkmenistan and Kazakstan, has no outlet to the sea. This fact has been a major sticking point in talks over its development as the states quibble over whether it is a sea or a lake. If a lake—as Russia and Iran have maintained—then it should be owned jointly with each bordering state having the right to develop whatever project it chooses, with no geographical barriers. If a sea, as others maintain, then each republic would have a clearly defined maritime border within which it would be permitted to operate.

Recently, Russia has given indication of being willing to compromise. It has proposed (with the support of Kazakstan) dividing the seabed, but not the water itself, into national sectors. The other republics have given mixed responses to this proposal. Nevertheless, a meeting of the leaders of these states has been scheduled for May or June 1998 for further discussions. However, reaching an agreement on the status of the Caspian is easier compared with the problems of transporting the oil and gas to where they are needed. The reserves being landlocked, several routes to markets have been proposed; none without problems. All involve long pipelines: across Russia to the Black Sea, across Azerbaijan and Georgia to the Black Sea, across Iran to the Middle East Gulf, or across Turkey to the Mediterranean, to name a few.

The first flow of crude oil from the Caspian Sea to the West, since the breakup of the Soviet Union, occurred in November 1997 signaling the success of a 3-year effort by the former Soviet Caspian republics, backed by the United States, to break the Russian blockade of energy exports from the region. Calculating that the Russian economy would improve on its own, some Russian financiers wanted to keep more of the oil for themselves, even if it meant forgoing foreign money and technology and letting the crude oil simply remain in the ground. Now that the oil is flowing again in the Caspian region, western oil companies are more willing to invest in the area.

Oil major Chevron has invested $700 million in a joint venture to develop the Caspian Region, particularly the supergiant Tengiz oil field in Kazakstan and has committed itself to investing an additional $10 billion during the next several decades. Mobil Oil also owns a 25% stake in the Tengiz oil field project. However, the Russian Federation has made concerted efforts to block the development of the proposed $4.5 billion Caspian Pipeline Project. Construction of this 1,000-mile link from the Tengiz oil field in Kazakstan west to the Russian port of Novorossiisk on the Black Sea was scheduled to begin in early 1998 and be operational by November 1999. However, the Caspian Pipeline Consortium, which is managing the project, had failed to obtain the necessary building and construction permits from local and regional governments as a result of Russia's blocking efforts. Consequently, Chevron, with the support of other oil majors, temporarily froze its funding of the project because of its lack of progress pending the results of talks scheduled in Moscow in March 1998, which now aim at starting the pipeline by 2000 and at getting the project operational by the fourth quarter in 2001.

In the meantime, Lukoil's Alekperov continued to acquire pieces of lucrative oil deals throughout the former Soviet Union. He managed to acquire a 12.5% stake in Chevron's Tengiz export pipeline in Kazakstan and may negotiate for another 10% or so.

Russia and Kazakstan still dispute the status of certain areas of the Caspian. For example, Moscow gave a gas and oil concession to Lukoil in the northern Caspian that overlaps with Kazak territory. This area is estimated to hold between 150 million and 600 million tons of recoverable oil reserves.

Kazak leaders hope that friendly diplomacy with Russia will solve the problems between these two former Soviet republics.

Kazakstan hopes to begin producing oil from its Caspian Sea reserves by 2003. "The government has set for itself the goal of producing 5 million tons (100,000 b/d) by 2003–2004 and of raising that to 50 million–60 million tons (1 million–1.2 million b/d) 10 years later," said Kenzhebek Ibrashev, chief executive of Kazakstan Caspishelf (KCS). The KCS consortium could begin exploration drilling offshore as early as summer 1998.

Yuksi

On Jan. 19, 1998, the controlling shareholders of Russian oil giants Yukos Oil Corp. and the Siberian Oil Co. (Sibneft) signed a letter of intent to combine the management and operations of the two companies thus creating the world's largest oil company in terms of proven oil reserves and the third largest in the world for *pro forma* 1996 oil production.

The new holding company was named Yuksi; 60% of the company's equity would be held by Yukos and 40% by Sibneft. "The objective of this combination is to create a world-scale and world-class integrated oil company with strategically located operations throughout Russia," said Mikhail Khodorkovsky, Yuksi's president. The transaction also reflects the trend, endorsed by former Prime Minister Chernomyrdin, toward consolidation in the industry by creating a smaller number of better capitalized and more globally competitive Russian oil companies.

The combination of Yukos and Sibneft represents the first merger of two major Russian companies. As of January 1998, the combined company had proven reserves of 13.9 billion bbl. Production of the companies comprising Yuksi was about 475 million bbl of crude oil or 1.3 million b/d in 1997. This represents about 22% of Russia's crude oil production.

Geographically, the combination places the five refineries and four active producing regions all within close proximity to one another, creating the potential for significant cost savings and economics of production. "Yuksi will benefit from the joining of ... two highly complementary upstream and downstream businesses. It will lead to improved efficiencies in production and distribution and a higher level of customer service," said President Khodorkovsky.

Yukos. Yukos and its subsidiaries constitute one of the larger vertically integrated oil companies in Russia for reserves. Established as an open joint stock company in April 1993, the government subsequently sold its shares to private investors in a series of auctions and tenders. It is the first Russian oil company to become wholly privately owned.

Yukos operates through its subsidiaries, which include two oil and gas exploration and production companies, and refining and refined products distribution and sales. It also operates about 1,000 service stations in the European part of Russia (west of the Ural Mountains). In 1995, the company won nine tenders and received licenses to explore and develop new fields in the Khanti Mansisk and Tyumen regions in Western Siberia. Yukos then added a production company, a refinery, and a number of research, marketing and distribution companies through its acquisition of Eastern Oil in December 1997.

Yukos is also negotiating with Amoco on the possible development of the Priobskoye field, one of the largest onshore fields in Russia.

Siberian Oil Co. (Sibneft). Sibneft is also among the larger integrated oil companies in Russia. Its operations span the range of oil activities from exploration and development to production, refining and distribution of petroleum products. Sibneft was established as an open joint stock company in September 1995 and began integrating its operations in May 1996.

In a series of auctions, which began in January 1996, private investors acquired 49% of Sibneft's share capital, with the rest remaining in the hands of the Russian government. In May 1997, the right to manage these government-owned shares was auctioned resulting in 51% of the company's shares being managed by private investors.

The company plans to increase production output from its current 355,000 b/d by:

- Combining a substantial workover program.
- Converting nonoperating production wells to injection wells.
- Continuing selective development drilling.

The 1997 development program recommended bringing 214 new producing wells and 110 injection wells on stream and developing the Eastern Vyngayakhinskoye field.

Sakhalin And Far East Development Projects

The Sakhalin Region consists of Sakhalin Island and the Kuril Island chain and occupies an area of more than 87,000 km² surrounded by the Sea of Okhotsk, the Sea of Japan, and the Pacific Ocean. Decreasing onshore reserves of oil and an increasing demand for oil products led to a search for new oil and gas deposits offshore. The first oil deposit was discovered in 1977 northeast of Sakhalin Island. During the subsequent two decades, five offshore reserves, holding an estimated 273 million tons of oil, 878 billion cu m of gas, and 64 million tons of condensate were discovered. Unexplored offshore reserves are estimated to contain an additional 450 million tons of oil and 700 billion cu m of gas.

Unable to develop the offshore Sakhalin reserves because of lack of the necessary funds and technology, the Russian Federation issued several tenders between 1991 and 1997 inviting foreign oil companies experienced at drilling in Arctic conditions to participate. As a result, three separate tenders—Sakhalin 1, Sakhalin 2, and Sakhalin 3—were won by several leading oil companies.

Sakhalin 1. The Sakhalin 1 project is being developed by an international consortium (Table 1). The consortium will mine three oil deposits—Chaivo, Odoptu, and Arkutun-Dagi—estimated to hold 310 million tons of oil and condensate and 335 billion m³ of gas. The fields are located 8 to 12 km northeast of Sakhalin Island in 20 to 55 m of water. The area is seismically active and covered with ice about 50% of the year. The total cost of the project is estimated at $15 billion.

Following the appraisal and evaluation of the fields, the consortium will start development using large, ice-resistant platforms and subsea templates. To support the project, special facilities and a pipeline will be built, along with other infrastructure needed for implementation of the project. The first production of oil is planned for 2000 at Arkutun-Dagi.

TABLE 1. INTERNATIONAL CONSORTIUM DEVELOPING SAKHALIN 1.

Company	Nationality	Percentage
Exxon Neftgaz	U.S.A.	30%
Sodeco	Japan	30%
Rosneft-Sakhalin	Russia	23%
Sakhalinmorneftgaz	Russia	17%

In 1996, the consortium spent more than $200 million to complete development plans and conduct resource appraisal and evaluation programs at the Arkutun-Dagi field. A 3-D seismic survey was conducted before drilling the first well (2,500 m), 20 km from shore. In 1997, $150 million was allocated for a 3-D seismic survey at Chaivo; for drilling three additional testing wells at Arkutun-Dagi, two of them using the *Okha* drilling rig belonging to Rosneft-Sakhalinmorneftgaz; and for Stage 1 of the exploitation phase of the project in the central area at the Arkutun-Dagi fields.

Sakhalin 2. The Sakhalin Energy Investment Co. Ltd. has obtained the support of the Russian Federation and of the Sakhalin Region administration to develop the Lunskoye and the Piltun-Astokhskoye oil and gas fields, offshore Sakhalin Island in the Russian Far East. The plan, known as the Sakhalin 2 project, is based on a phased approach to developing these fields, which is expected to lead to production in 1999. This project is the first development scheme offshore Sakhalin, an area that has the potential to become a major oil producing region.

Lunskoye is a gas field with associated oil and condensate, and Piltun-Astokhskoye is an oil field with associated gas. These fields are estimated to contain 100 million tons of oil and condensate and 494 billion cu m of gas. They lie in an inhospitable environment with hostile climate and difficult geological conditions, with the ice season lasting up to 9 months, water depth ranging from 30 m to 50 m, and seismicity reaching Magnitude 8 on the Richter Scale. The project is estimated to cost $10 billion.

The development of the Sakhalin 2 project is coordinated by the Sakhalin Energy Co. Ltd., which was established in 1994 by an international consortium that includes Marathon Oil, Mitsubishi, Mitsui, and Shell Oil as shareholders. Development of the project will last about 10 to 15 years. The production will be transported to the shore by pipeline and then to the south of the island for processing at an oil terminal and liquefied natural gas plant prior to export. The first phase of development will use Molikpaq, a mobile ice-class drilling unit. The extracted oil will be transported by a short pipeline to an anchor leg mooring buoy and a storage anchor for subsequent loading onto tankers.

In 1997, Sakhalin Energy began a land survey for pipeline and housing construction for expatriate employees. The company faces other infrastructure challenges such as terminals, loading facilities, and a gas liquefying plant. The company is also actively working to secure legislation and regulations needed to support its large investment. The Sakhalin 2 production sharing agreement provides for payment to the Russian Federation of 8% royalties and income and production in the form of oil and gas (51%).

Sakhalin 3. Sakhalin 3 is another project that will have U.S. participation. Although agreements have not yet been finalized on production sharing, Exxon will develop the Vostochno-Odoptinskoye and Ayashskoye fields, whereas Mobil and Texaco will develop the Kirinskoye field. These fields, which comprise an area 15,000 5q km, have not yet been surveyed but are believed to have promising oil and gas reserves. The estimated survey period will last 5 to 10 years.

Once a production sharing agreement is reached and approved by all parties, Mobil and Texaco will invest $150 million to survey the first field; Exxon will spend $300 million to survey the other two. Mobil, the project operator, will finance the modernization of the Shelf 6 drilling unit and will invest $1.5 million to build a drilling rig for the Kirinskoye field.

The Russian oil industry has made great strides in the past few years. With the support of the government, it will continue to pursue the trend toward greater privatization and association with Western oil companies and achieve better capitalization and global competitiveness than it did under the Communist regime, when the oil resources were operated by a central planning system without outside cooperative investments. ●

Dual Bore Re-entry, Tern Platform MLR Highlight Multilateral Action

Schlumberger Anadrill and Secure Oil Tools agree on distribution of Secure's Multilateral Production System.

Staff Report

Sperry-Sun Dual-Bore MSCS Allows Selective Re-entry

Sperry-Sun, a division of Dresser Industries, Inc., successfully installed the first 9⅝-in., dual-bore, Multi-String Completion System (MSCS™) with an MSCS vector block. A vector block allows selective re-entry into each string of an MSCS completion. The MSCS dual bore completion system provides a mechanical seal for hydraulic isolation of the junction between the 9⅝-in. main bore and the 4½-in. lateral casing strings. It was used to isolate and eliminate sand production from the upper lateral. Prototypes of these systems were constructed in 1995 and were field tested extensively in 1996.

The completion was installed for Corpoven SA (now PDVSA) of Venezuela in a 9⅝-in. Lateral Tie-Back System (LTBS™) junction. The MSCS vector block was installed immediately above the MSCS dual bore to allow commingled production from the two lateral well bores while enabling selective re-entry into either one. This system used two 3½-in. tubing strings to line and seal into the packer placed in the main bore and into a seal bore within the cased lateral. The two strings were then joined at the vector block for commingled production.

The MSCS was installed a year and a half after the well was put on production. Production was suspended, tubing was retrieved, and the well was circulated to clean the main bore. An isolation plug was installed in the main bore tie-back hanger below the window joint to shut in production. Sperry-Sun's latch system correctly positioned the workover whipstock, which was oriented to the upper lateral. Completion tubing was run into the upper lateral to clean out the 4½-in. slotted liner, then the whipstock was retrieved. After retrieving the main bore plug, a second clean-out trip was completed to remove sand from the main bore.

A single string packer was attached to the MSCS dual bore deflector via a tailpipe. The deflector was oriented to the latch coupling for proper alignment and the packer was set. The deflector simultaneously guided a 3½-in. tubing string into the upper lateral and a second 3½-in. tubing string into a seal assembly in the main bore. The MSCS vector block was then installed to connect the two strings below to a single monobore string. A production pump was placed immediately above the vector block to pump the commingled production. Production has increased significantly since installation, and the absence of sand indicates successful hydraulic isolation of the lateral junction.

PCE Completes 14th MLR—One On Shell's Tern Alpha Platform

Pressure Control Engineering (PCE), a UK-based Tuboscope company, has installed a total of 14 Multi-Lateral Re-entry (MLR) systems to date. One recently implemented on Well No. TA-17 on the Tern Alpha platform, operated by Shell UK Exploration and Production, illustrates the value

Fig. 1. The coiled tubing is deployed through a tubing diverter in the casing window.

of this type of completion.

First discussions with PCE about the prospect of completing the Tern well as a multilateral took place in March 1996. One of the challenges facing the Tern field development team was how to add a level of predictability and certainty to their project to optimally produce the Triassic formation, which had discrete 3-D sand bodies with the best production from relatively thin intervals penetrated by horizontal wells. Early in the development phase, there was considerable uncertainty concerning flow paths between those sand bodies and therefore high risk of inefficient sweep under a waterflood development scheme.

The Tern team worked with three main development well design priorities:

- The ability to selectively re-enter the lateral at any time and carry out logging or stimulation procedures using coiled tubing—without removing the upper completion.
- The ability to set bridge plugs to isolate a portion of the lateral or isolate it completely should conditions so dictate during the life of the well.
- The ability to create a flexible system able to respond quickly to circumstances difficult to predict.

The decision was made to complete Tern Well No. TA-17 to at least TAML Level 4. Working closely with well services consultant Egis, the team selected PCE's MLR to meet the stringent requirements of this project.

By October 1997, the upper lateral had been drilled through a pre-milled window at 8,118 ft and was cased, cemented and perforated. Following the construction of the junction by removal of the upper lateral liner top from the main bore, the lower completion with the lower packer and nipple assembly was run into the hole and locked into the correct position. The upper completion was then run with a packer stung into the MLR nipple.

An internal diverter was subsequently run through the upper completion and located in the MLR nipple, as shown in Fig. 1. This shows how the diverter lined up perfectly with the window in the MLR nipple, which itself was lined up to the casing window by means of a big bore latch assembly placed in the casing window latch collar.

Accuracy is crucial to allow intervention tools to deploy freely into the upper lateral; tolerances for depth must be within a fraction of an inch, and tolerances for orientation within a few degrees.

After the diverter was installed, a drift run confirmed lateral access; then a third run set a bridge plug in the upper lateral to isolate its perforations and enable underbalanced perforation of the main bore. With the bridge plug set and tested, the diverter removed and a straddle sleeve inserted across the window, the completion packers were set, thus hydraulically sealing the junction for the life of the well.

With work on the main bore completed, the diverter was replaced to allow a pulling tool to be run into the upper lateral to retrieve the bridge plug. Unfortunately, the pulling tool string failed to deploy into the upper lateral.

Since the initial successful deployment of the bridge plug into the upper lateral, the completion packers had been set and the main bore perforated in three runs using long strings of coiled-tubing-conveyed guns. After several unsuccessful attempts to re-enter the upper lateral, uncertainty arose regarding the depth and condition of the MLR locating profiles. Consequently the straddle sleeve was reinstalled, allowing oil production while various obstacles to re-entry were considered.

The recovery program involved thorough cleaning of the MLR locator profiles and accurate correlation of coiled tubing depth with these profiles. PCE designed, manufactured and tested a dedicated tool for this purpose. Upon re-entry of the well, the straddle sleeve was removed, the well bore circulated clean in the area of the MLR nipple with the aid of a coiled tubing venturi junk basket and the depth and integrity of the location profiles was accurately determined by the newly designed tool.

On the next run, the diverter was set on the first attempt and the correct setting depth was confirmed by the earlier correlation run. A subsequent run with a full-bore fluted drift proved correct orientation of the diverter and allowed lateral access.

Eventually the pulling tool was deployed and the bridge plug was successfully pulled. Although it was initially feared that movement of the MLR nipple relative to the casing window or component failure could have been the cause of the re-entry problem, it turned out that the problem was merely a build-up of debris across the lateral window combined with uncertain coiled tubing depth. As is the case with many multilateral well operations, depth control and debris management played a crucial role in this operation.

Both the upper lateral and the main bore are now flowing oil. However, 3-4 months of production from the main bore caused a difference in reservoir pressure between the two zones. This highlighted the importance of being able to isolate the lateral with a pressure sealed straddle if needed.

Using a multilateral well, the Tern field development team was able to combine appraisal and development targets in one well, accessing oil which might otherwise not be economical to recover with a single well. Key to this success was having all relevant parties working together at the planning stage to help achieve the common goal of maximizing return on investment.

Secure Oil Makes MLPS Distributorship Agreement With Schlumberger Anadrill

Secure Oil Tools, a division of Stellarton Energy Corp. of Calgary, has signed a letter of intent with Schlumberger Anadrill. The letter of intent is a precursor to a formal agreement that will allow Anadrill to distribute Secure's Multi-Lateral Production System (MLPS) on an exclusive basis in most regions of Africa, South America, the Middle East, and southeast Asia. Excluded are clients and regions in which Secure is already selling the products. Anadrill will also have the right to market MLPS on a non-exclusive basis elsewhere in the world.

Secure has developed a system to provide for the drilling of one or more laterals out of a primary wellbore. Successes in the Peace River area of Alberta, Canada, have created the opportunity to market the concept around the world.

Secure will provide engineering, design, manufacturing, sales support and installation of the products. Anadrill, whose core product lines are directional drilling and MWD/LWD, will provide marketing and technical sales, logistical bases and support, access to testing facilities and a wealth of well experience. Anadrill has demonstrated commitment to the pending agreement and the marketability of the Secure MLPS system with a commitment for a prepayment against future sales. ●

MDC Technology Optimizes Shell's Tern Platform

World's First Offshore Closed Loop Optimizer

Optimization technology has evolved as a real-time tool for controlling process plants, and has recently been implemented on the first offshore platform with excellent results.

Technologies for plant process optimization have generally tracked the advances made in the computer industry. Process control computers began to penetrate the market during the 1960s, marking the start of real-time optimization in the process industries.

Some of the earliest examples of real-time optimization were in the ethylene industry, bulk petrochemical processes and refineries. All of these industries shared a number of common features, principally that they are high-throughput processes operating in highly competitive markets where small differences in margin separate the leading operators from the laggards.

Optimization In The Oil And Gas Industry

By contrast, the upstream oil and gas industry has only recently focused on process optimization, having previously concentrated on the fundamentals of finding reserves and exploiting them. The technology emphasis has been on reservoir description and hydrocarbon production rather than processing. Particularly in the offshore sector, the cost pressures imposed due to increased competition and lower oil prices have been very evident through initiatives such as CRINE. This has been largely directed toward new capital investment rather than improving the performance of existing assets.

The industry is accustomed to optimizing design based on cash flow and other parameters. It is also familiar with using off-line optimization tools for production planning and scheduling. It is therefore a little surprising that oil and gas producers have not adopted real-time optimization more extensively, especially since accelerating oil production by only 1% can result in a larger net present value (NPV) and excellent payback on even small and medium-sized assets. Of course, there are significant technical challenges in successfully implementing closed loop optimization offshore, but the world's first optimizer has shown that these can be overcome.

Types Of Optimization

From the user perspective there are three basic types of optimization applications (Fig. 1):

- Off-line optimization—typically for planning applications.
- Open loop real-time operation—for operator advice.
- Closed loop real-time optimization—for process control.

The oil and gas industry has made extensive use of the first type as an operational tool, and there are a few examples of open loop optimization in onshore fields and in gas processing plants. However, there are no known examples of closed loop optimization offshore other than the recently completed project by MDC Technology for Shell UK Exploration and Production's Tern platform.

In the current climate, operators are looking to squeeze the maximum value out of their assets. Therefore technologies such as real-time optimization are likely to play an increasingly important role in platform operation.

The Tern Project

Tern is a medium-sized, gas-lifted oil production platform operated by Shell Expro in the UK sector of the Northern North Sea. It processes produced fluids from both the Tern field and the neighboring Hudson field

by A.S. Mortimer, MDC Technology Ltd.

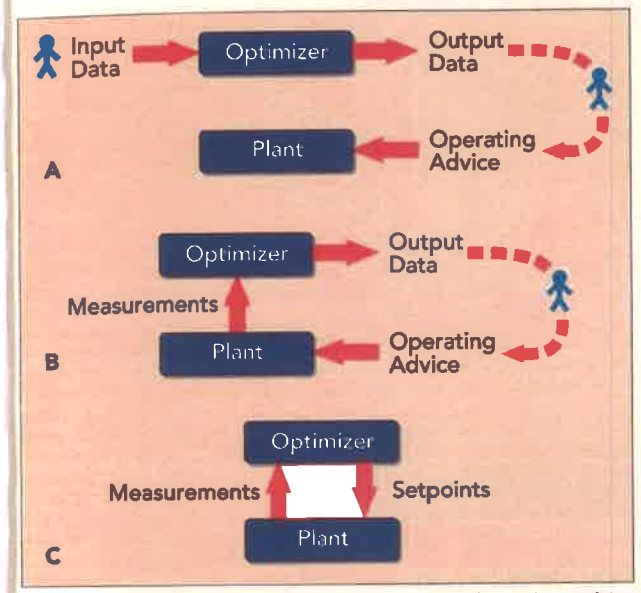

Fig. 1. There are three types of optimizers: a) off-line optimizers, b) open loop, real-time optimizers and c) closed loop, real-time optimizers.

The topsides processing equipment comprises three single-stage separation trains and twin three-stage lift gas compressors (Fig. 2).

The Tern platform was specifically chosen by Shell Expro to host this project for several reasons:

- It is a fairly large producer (70,000 to 90,000 b/d) and is expected to have a long field life (until at least 2010).
- Tern had been debottlenecked several times since it was commissioned, and Shell Expro recognized the potential for additional production by optimizing the process.
- Most wells were gas lifted and capacity was shared with other fields and platforms, presenting a complex operating problem.
- The platform had modern control and instrumentation that provided a good existing infrastructure for an optimization application.

Optimization of the gas-lifted Tern platform required a whole systems approach to address well performance, topsides equipment and lift gas distribution. The mission was to determine how to use the available lift gas and define the topsides operating conditions (pressures and temperatures) to achieve maximum economic return.

Production Scenarios

A closed loop optimizer has to deal with all modes of operation, and for Tern there are three main cases:

- Production limited by well potential.
- Production limited by lift gas availability.
- Production limited by topsides processing capacity.

The Tern optimizer must address all of these scenarios because well workovers or compressor or separation train outages can significantly change the relative capacities of the three main parts of the process. One particular scenario may be dominant for significant periods of time, but alternative regimes can occur sporadically. Furthermore, the dominant scenario is likely to change over the longer term. A platform may begin with topsides processing capacity limits, then experience lift gas limits followed by a well potential limiting regime as field production comes off plateau.

During the feasibility study for the Tern optimizer project, topsides processing capacity limiting was the dominant scenario, but during commissioning, circumstances had changed; the well potential limited scenario had become dominant. Currently, the platform is both topsides and lift gas limited.

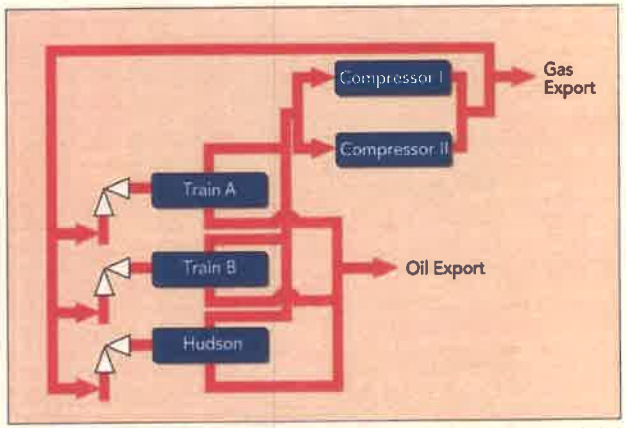

Fig. 2. The topsides processing equipment for the Tern and Hudson fields included three single-stage separation trains and twin three-stage lift gas compressors.

Degrees Of Freedom

The Tern optimizer addresses the three main effects which dominate process behavior:

- The distribution of lift gas among the wells.
- The trade-off between well productivity and total lift gas availability through manipulating topsides conditions.
- Recovery of NGLs from the gas stream.

The problem was further complicated by the presence of a variety of constraints around the topsides.

This was a constrained optimization problem typical of those found in the process industries, in which the optimum condition has a high proportion of the variables at their minimum or maximum limits with the remainder at intermediate positions. Those variables at intermediate positions usually balance against one particular downstream constraint. It is difficult for an operator to determine what are the correct limits to push and to choose setpoints that actually achieve the objective of operating on these limits.

The topsides capacity aspect of the Tern problem is similar to the problem described above. However, the lift gas distribution problem is unusual in that the variables rarely lie on their bounds at the optimum conditions. The existence of this "internal" optimum is due to the nature of the well performance relationships.

For any given quantity of lift gas there will always be an optimal distribution of this gas among the operating wells, and any other distribution pattern will result in lower oil production. If there are no constraints on the wells themselves, this occurs when the marginal Gas Utilization Factor is equal for all wells (Fig. 3). This means the wells would be operated at a rate where an additional cubic meter of lift gas would produce the same amount of additional oil for every well.

Flow stability criteria and valve or flowline capacity constraints prevent all wells from operating at identical Gas Utilization Factors. Typically the largest and the smallest producers optimally operate at the lift gas flow

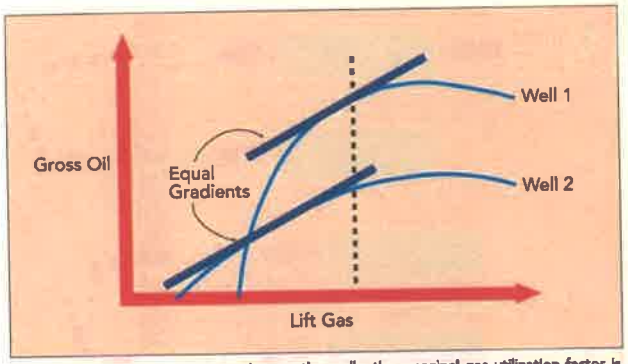

Fig. 3. When there are no constraints on the wells, the marginal gas utilization factor is equal for all wells.

limits, while the remaining wells are optimized with equal Gas Utilization Factors. When Tern has the optimizer in operation, roughly 70% of the wells produce with equal Gas Utilization Factors.

Tern Optimization Project History

This project was initiated with a feasibility study and functional design, followed by the implementation phase.

The feasibility study quantified the benefits that could be expected and also identified the key issues to be addressed as part of the project design and implementation. These included:

- Elimination of bottlenecks such as incorrect pump trip settings.
- Fixing instrumentation and measurement problems. For example, impulse lines on lift gas meters were traced to eliminate hydrate formation problems.
- Improvements in well test data quality for improved characterization to optimize well performance and for off-line use by production technologists.
- Consistency between the closed loop optimizer and Shell's proprietary off-line design simulation tool for production technologists.

The economic analysis quantified the benefits expected from various options and recommended that a closed loop optimizer be installed. It also provided the terms of reference for the functional design specification, which formed the baseline document for the subsequent project implementation.

The main features of the Tern optimizer application are:

- Well performance models based on design simulations and updated from validated well tests.
- An on-line "base case" model of the wells and topsides automatically updated from validated process measurements.
- A closed loop optimizer which provides setpoints for gas lift flow controllers and compressor interstage temperature controllers every 10 minutes.
- An interface in the DCS to enable the process operators to monitor the performance of the optimizer and to open and close loops.
- An open loop optimizer advising on the best line-up of wells to separation trains.
- An off-line "What-if" optimizer for use by onshore process engineers for case studies and as an aid to monitor the performance of the closed loop optimizer and its benefits.

Flowline Slugging

One unforeseen problem which arose during optimizer commissioning was the extent and severity of slugging on the Hudson production lines and the subsequent impact of this on the whole topsides process.

Hudson produces via a subsea manifold and a long flowline, and fluids are processed on the Tern platform. The slugging problem can be attributed to the geometry and flow regime of the flowline. Investigation and resolution of the slugging problem was not part of the Tern optimizer project, and the project therefore had to develop an enhanced strategy to deal with the symptoms of slugging on the Tern process.

Of course disturbances and the absence of a true steady state is characteristic of all process plants. The unusual factor for the Tern optimizer was the severity of the problem, largely but not exclusively due to Hudson. The main elements of the strategy for handling unsteady processes are:

Single point data conditioning or filtering to eliminate noise.
Model-based validation to eliminate inconsistent data.
Base-case matching.
Steady-state checks.
Dynamic compensation for constraint projections.

The effectiveness of this treatment—even under the severe test posed by slugging on the Hudson process—is shown by the fact that the optimizer achieved an uptime in excess of 90% of process stream time.

Benefits

The direct benefits from the optimizer were measured using a quantitative technique called "shadow operation." This involved two sets of trials, the first of which established how much benefit is potentially available from the closed loop optimizer, the second set measured how much has been actually achieved. The direct benefits for the project were calculated to be 2.5% accelerated oil production.

The Tern optimizer has been operating in closed loop for more than 9 months and has demonstrated the successful transfer of this technology into the offshore environment. Robust and reliable performance has been achieved, and overall benefits equivalent to 2.5% accelerated oil production have been delivered. Similar benefits can be expected on other assets of similar size. ●

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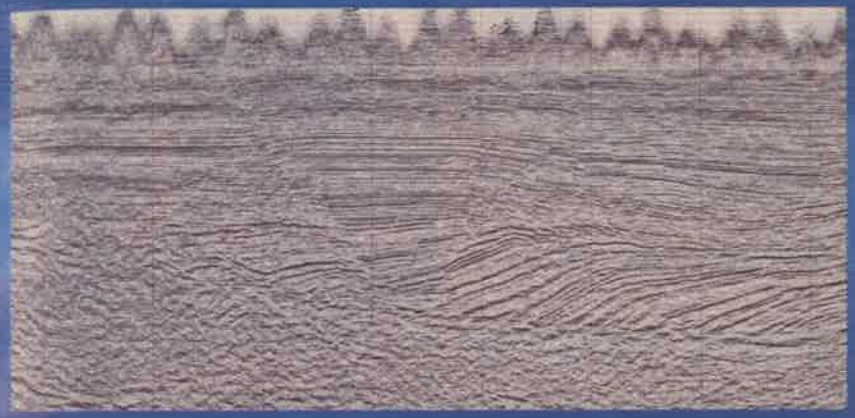

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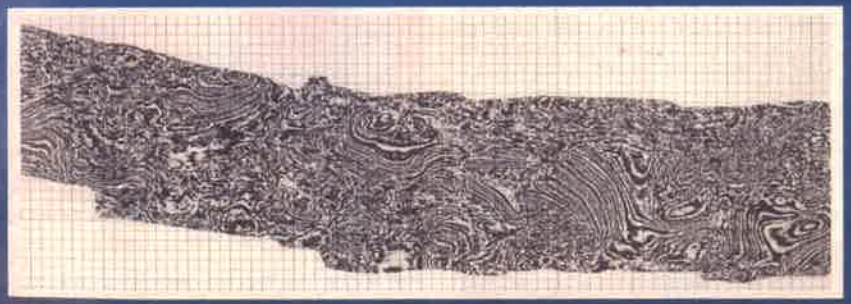

OBS 3D Time Slice

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Predicting And Preventing Casing Wear While Drilling

Based on more than 300 casing wear experiments, a computer program was developed to calculate the potential for casing wear during drilling operations. Taking proper precautions can save operators more than $1 million per well.

Drillpipe rotating inside a well's intermediate string of casing has long been recognized as the principal cause of internal casing wear. Because today's wells are longer and deeper than ever, prolonged contact can cause sufficient wear to either breach the casing or weaken it to the extent that it will rupture when the casing is pressure tested, delaying the project while an unplanned tieback casing string is installed.

The locations most susceptible to wear are doglegs and "wiggles" in the upper part of the hole, where high tension loads in the drillstring hold the rotating tool joints against the casing with up to 10,000 lb of force (Fig. 1). As the tool joints gall and grind their way into the casing wall, a crescent-shaped groove is produced, deepening as drilling progresses (Fig. 2). Failure to anticipate and compensate for the effects of this wear can lead to serious problems, such as lost circulation, casing collapse or blowouts, which can result in the loss of the well, loss of equipment—and even loss of life.

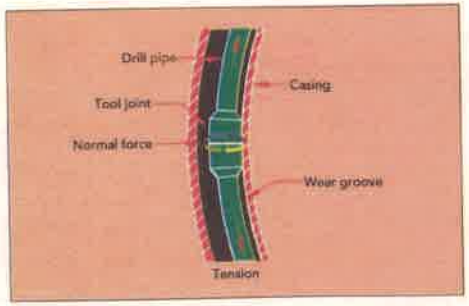


Fig. 1. A high tension-loaded rotating drill string creates wear potential in curved upper casing locations.

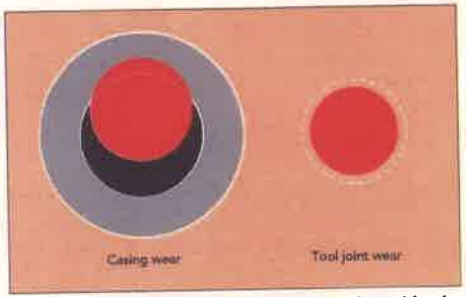


Fig. 2. This crescent-shaped casing groove was formed by the rotating tool joint wearing it down.

Anticipating the locations and extent of casing wear requires that the wear process be described mathematically. A process variable analysis which does just that was developed by Maurer Engineering Inc. as part of Drilling Engineering Association's Project DEA-42. A Windows-based computer program, CWEAR5, calculates the location and magnitude of casing wear in an individual well. Fig. 3 shows a sample of the output from CWEAR5.

The mathematical model states that the volume rate of casing wear is proportional to the frictional work done on the casing by the rotating tool joints. The constant of proportionality is called the wear factor.

by **Jeanne M. Perdue**, Technology Editor

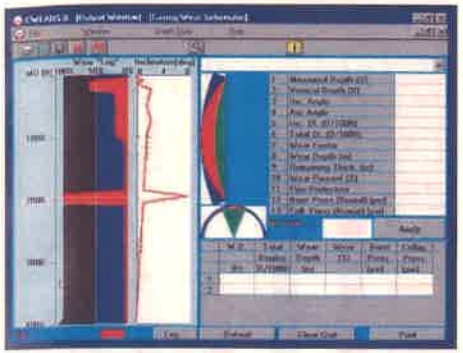


Fig. 3. One CWEAR5 output screen shows a casing wear log, a cross section of the worn casing, and a list of significant parameters at a pre-selected depth.

Wear Factor Determined Experimentally

Casing wear rate is influenced by:

- The tool joint material.
- The casing material.
- The mud system properties, such as solids content and lubricants.

The wear factor must reflect all three influences. Since there is no known way to calculate the value of the wear factor, it had to be determined experimentally. More than 300 casing wear tests have been run to accumulate the largest database of empirical wear factors in the world.

Casing wear tests were conducted in a casing wear machine that provided high lateral loads between the rotating tool joints and the casing. Schematics of the experimental set-up are shown in Figs. 4 and 5. Drilling mud was injected between the tool joint and casing to simulate downhole conditions. The tool joints were both rotated and reciprocated during the tests to simulate drillpipe movements while drilling. The entire test was computer controlled, with data electronically sampled and recorded.

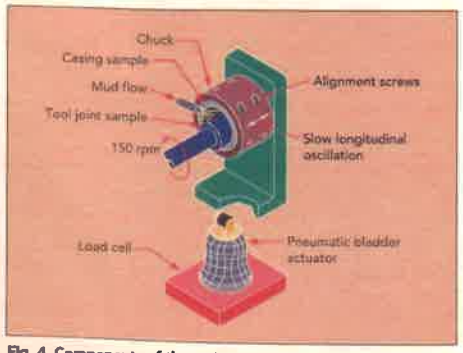


Fig. 4. Components of the casing wear test unit are indicated.

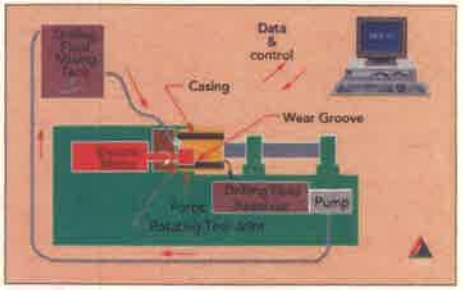


Fig. 5. This schematic identifies the control and data acquisition system of the casing wear test unit.

Fig. 6 shows an example of a 6⅝-in. OD tool joint wearing 48% of the way through a 9⅝-in. diameter piece of 47 lb/ft N80 casing in 8 hours, corresponding to 200 hours of drilling time. The empirically determined wear factors were input into the CWEAR5 computer program along with well geometry and the proposed drilling plan to predict casing wear in actual drilling situations. If unacceptable wear is anticipated, remedial measures can be included in the drilling schedule. Possible remedial measures include:

- Establishing and maintaining strict dogleg severity limits.
- Running heavier wall casing into those portions of the well where high wear is anticipated.
- Using proprietary hardbanding on tool joints in high wear regions.
- Using drillpipe protectors in the region where high wear is expected.

Monitoring Casing Wear

During drilling operations, casing wear logs can document the progress of wear. Comparing output from the CWEAR5 computer program with wear data from the logs will enable drillers to determine the well's unique wear factor. Using the well's actual wear factor, drillers can recompute the amount of wear to be expected during the remaining drilling operations. If needed, remedial measures can be introduced at this time.

The mud magnets must be observed carefully during drilling operations. Steel filings collected by mud magnets not only warn of excessive wear, but can also indicate the nature of the wear process. Fine steel powder indicates that grinding is destroying the casing. Needle-like slivers indicate that machining is taking place. This is usually the result of running tungsten carbide hardbanding in the casing, and should be attended to quickly. Flat shreds indicate that severe galling is taking place, and this demands immediate attention.

Fig. 6. The casing wear groove generated by a test is similar to those observed in the field.

With the technology available today, casing wear can be anticipated as the well is planned, monitored as the well is drilled, and, if necessary, remedial measures can be incorporated into the drilling program at any stage of the operation.

Hardbanding

An offshoot of the DEA-42 program has been the development of proprietary metals for tool joint hardbanding. The use of new materials such as ARNCO 200XT, ARMACOR M and PINNCHROME has given operators and contractors the ability to greatly reduce casing wear while protecting the tool joints in a cost-effective manner. Not only will these new materials help control wear, but they also significantly reduce frictional torque and drag, especially in horizontal and extended reach wells (Fig. 7).

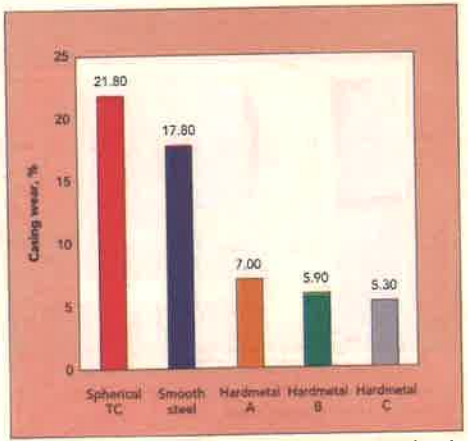


Fig. 7. Tool joints coated with new hardmetals offer significantly reduced casing wear compared to uncoated steel tool joints.

Deepwater Risers

The concepts of wear prediction and control developed during the past phases of this project are now being applied to the unique wear problems experienced in deepwater offshore operations, particularly wear in lower riser joints. The current phase of the DEA-42 program is aimed at predicting and controlling wear in deepwater offshore risers, where small changes in flexjoint angles can cause major riser wear problems.

Casing Wear Insurance

Application of this new casing and riser wear technology has significantly reduced the risks and overall costs of drilling and completing wells. According to Dr. Russell Hall Jr., senior scientist at Maurer Engineering, "The minimum amount of casing wear trouble starts at $1 million and goes up from there. If you can calculate casing wear, if you can measure casing wear, then you can reduce casing wear. It's like buying insurance."

Several major operators have saved more than $1 million per well using CWEAR5 to predict casing wear problems simply because they could avoid running additional strings of casing. Maurer Engineering is continuing to develop and improve casing and riser wear technology so that tomorrow's risks and costs can be further reduced. ●

Integrating Information Management Systems

Integrating scientific, operational, financial and administrative information systems based on workflow can increase efficiency and reduce the time wasted while locating information.

Although oil and gas prices have lost ground in the past few years in inflation-adjusted terms, operating costs and personnel costs have increased. The competition among all companies in the energy industry to hire the few qualified professionals available has created a frustrating and potentially dangerous situation. And since most experts do not expect prices to change much during the next few years, there remains only one solution: Figure out a way to get more work done with the same sized or even smaller staffs.

Increasingly, oil and gas companies are seeing the benefits of using information systems technology as a strategic tool to provide a long-term competitive advantage. Successful oil and gas production operations involve significant levels of information management across numerous professional disciplines. The expanded use of portable computers, when coupled with more functional and user-friendly computer software, has greatly reduced many of the labor-intensive processes involved in production management during the past 10 years. For example, word processors have given operators the ability to electronically track drilling, completion and maintenance reports, as well as easily and quickly compose letters or reports to investors, landowners and other interested parties. Spreadsheets allow for faster calculation processes and therefore dramatically improve the efficiency of the laborious analytical efforts required to track numerical information related to production management. And even more recently, first-generation relational databases enable mass storage of such information and provide very logical and effective systems for relating various informational aspects of oil and gas production. With communications technology advancing faster than any other single area in the high-tech industry, the improvements in information management can easily span the globe.

While each of these independent software solutions provides convenient access to a specific segment of information management, none has provided the cross-platform accessibility that could be obtained from a common data warehouse. As a result, today unfilled gaps still exist within growing organizations for the proficient use of computers as well as accessibility of critical information.

In order for oil and gas companies to develop functional strategies for implementing their own information management systems, they must first address several questions:

- What should be the objectives of computerized oil and gas information management systems?
- How should they be made a part of operational management strategies?
- Who should use the systems, and how might they affect filing systems?
- How will a database be populated?
- How will this affect a company's bottom line?
- How should a system be evaluated from a cost/benefit perspective?

The answers to these questions and more will lead to the definition of strategies and objectives for efficient production data management.

Identifying the actual workflow patterns within a company can help to determine whether an information management system can better facilitate that workflow, or simply end up creating even bigger workflow problems. Another important consideration is making certain that other employees who work with the system will be able to navigate through it easily, quickly and with as little training as possible.

Ideally, an information asset should comprise enough information and be organized sufficiently to support multiple disciplines within a company and enable business decisions from both a financial and non-financial perspective.

by Thomas R. Bandy and Jeffrey O. Dyk, Production Access Inc.

TABLE 1. TYPICAL COST SAVINGS FROM INTEGRATED IT SYSTEM

Employee Type	Cost	Units	Person Count	Hours per Mo.	Cost per Mo.	Annual Benefit
Executive Time	$100	Hour	1	10	$1,000	$ 12,000
Professional Time	$100	Hour	2	25	$5,000	$ 60,000
Administrative Time	$30	Hour	5	60	$9,000	$108,000
Field Man Time	$50	Hour	2	25	$2,500	$ 30,000
Total Value of Time Savings / Month /Year :			10	120	**$17,500**	**$210,000**

Most oil and gas companies today are in dire need of a way to keep a realistic blend of scientific, operational, financial and administrative information to effectively run oil and gas operations. In the most efficiently run companies, all of these mainstream information platforms depend on each other to be used effectively. However, the case with most companies is that the accounting department has a separate, stand-alone financial system, while the system for managing oil and gas properties generally includes a mix of fragmented spreadsheets, word processing documents and paper copies filed away somewhere. Seldom do these islands of scientific, operational, financial and administrative information get used effectively together in the critical decision-making processes. As a result, there is significant loss of professional time and effort from support staff, engineers, accountants, landmen and management. An entire company suffers when information is not used properly in the normal workflow of the business. The table above demonstrates a simple way to estimate the cost to a company of poor information management, based on lost time of 5 professionals and 5 support staff from inadequate information flow.

The computer program Production Access 3.0 was built with the normal workflow of the oil and gas operator in mind. A key objective in designing Production Access was that the information serving the needs of an entire operation should be entered one time and then immediately transported to wherever it is needed within an organization. Because the information is available to all individuals that need it, the efficiency of all departments within that company is increased significantly, allowing greater focus on production optimization, cost control and revenue enhancement activities. From project development and monitoring, to partner/investor relations and reporting, to the drilling, completion, stimulation, production, maintenance and equipping phases of a well or lease, information is warehoused in a series of integrated data files. This integrated approach to data warehousing allows the Production Access modules to capture information "centrally" and serve the numerous disciplines within a company that require the information to conduct their business.

The result is that a field office can enter daily reports from remote locations using appropriate communication technology and then company management can have immediate access to that same information in any report form desired. Similarly, the accounting department can enter an invoice billed to a particular property and then immediately send individual partial invoices to partners. With this same keystroke effort, the engineering manager or the field superintendent can immediately see the costs incurred on that property. It is this type of investment in data warehousing that yields tremendous returns in the form of well-informed decision making at any level in an organization. The various professions are allowed common "life-cycle" asset information through client-server technology of Production Access.

The most efficient information management systems of today must figure out a way to logically distribute, in a normal workflow manner, constantly changing information in a variety of disciplines within a company.

It is not uncommon for drilling and completion records, maintenance, production, sales, costs, and revenues on every well or lease to change constantly for many different reasons. Unfortunately with most companies today, the processes for monitoring these functions are cumbersome and prone to error because of the wide variety of fragmented data sources that must be compiled to produce a successful management document. Because these sources are scattered—and not consistently updated—the information becomes stagnant to a point in time, rather than dynamic to the change in time. For companies to compete successfully in the future in the oil and gas industry, they must treat the commitment for investing in information management to be every bit as important as the investment to acquire acreage, shoot 3-D seismic or drill a well. Progressive companies will figure out a way. ●

ABOUT THE AUTHORS

■ **Thomas R. Bandy** joined Production Access in the fall of 1997 and serves as president and CEO. He has a BS in petroleum engineering from Montana Tech. After working in the industry in various petroleum engineering capacities from 1976-1982, Bandy founded and sold two energy service companies. Most recently, he was chairman of the board of ProTechnics Co., a company he founded in 1983 that was sold to Core Laboratories in December 1996.

■ **Jeffrey O. Dyk** is vice-president and chief operating officer of Production Access. He earned a BS in petroleum engineering in 1981 from Montana Tech. Dyk worked for Texas Oil & Gas, Rangeline Corp. and McCoy Petroleum from 1981 to 1994, when he formed Production Access.

Innovative Applications Emerging For Hydraulic Jet Pumps

When smaller jet pumps are combined with coiled tubing in innovative ways, sharply lower costs of well testing and production can result.

Jet pumps have long been an accepted means for artificial lift. The basic lifting operation is illustrated by the jet pump cross section in Fig. 1. Momentum of one fluid (the power fluid) through a nozzle generates a differential pressure that draws in the produced fluid which is mixed and carried upward.

Standard well configurations use production tubing for high-pressure power fluid input, and the mixture of power fluid and produced fluid returns up the tubing/casing annulus. Now smaller jet pumps with high efficiency and longer life are resulting from recent improvements in design and metallurgy.

Units can be 0.94 in. OD and 6.64 in. long or 1.17 in. OD by 8.10 in. long. These can be installed and removed through 1 in. ID and 1¼ in. ID coiled tubing and can lift up to 3,000 b/d and 10,000 b/d, respectively. When combined with coiled tubing, they make possible several new and innovative applications in well test and artificial lift installations.

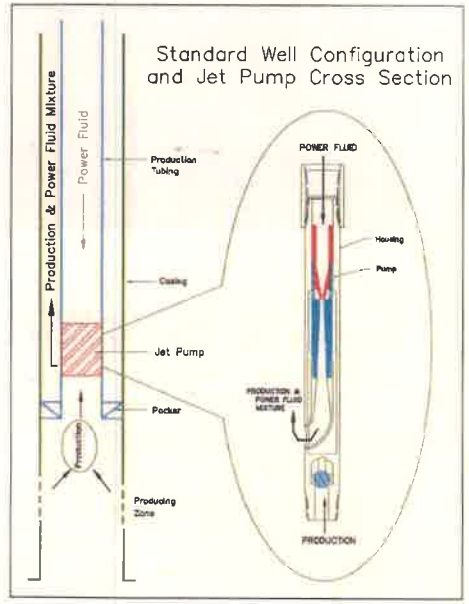


Fig. 1. Standard well configurations use production tubing for high-pressure power fluid input, and the mixture of power fluid and produced fluid returns up the tubing/casing annulus. A simplified jet pump cross section is shown.

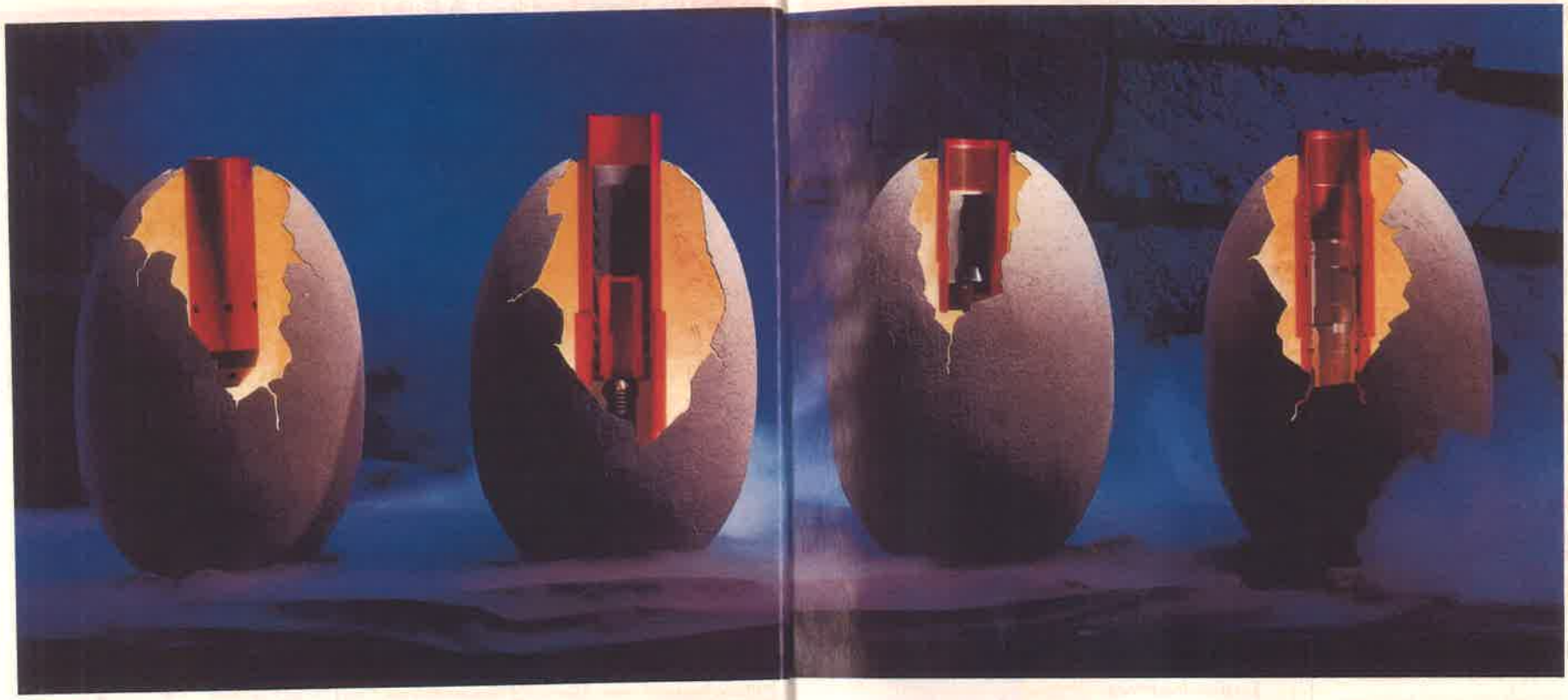
Jet Pumping Wells With SCSSV

One new application occurs in installations where natural well flow may be achieved, an SCSSV is required, or both.

The standard flow can be reversed using a crossover sub, as shown in Fig. 2, run as a pump seat. Power fluid may then be pumped down the annulus and production returned up the tubing ID and SCSSV. Using a power fluid density sufficient to overcome static BHP assures safety system integrity.

In this configuration the jet pump cannot be reverse-circulated to surface and therefore is designed for

by C.O. "Doc" Stokley, TAM International, and T. Roland Jackson, New Coleman Pump Co.



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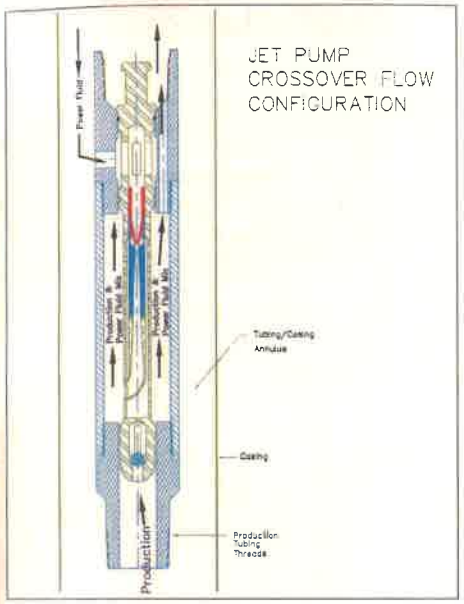

Fig. 2. The schematic is a configuration using crossover sub run as a pump seat. Power fluid is pumped down the annulus and production returned up the tubing ID and SCSSV. Sufficient power fluid density is used to overcome static BHP and assures safety system integrity.

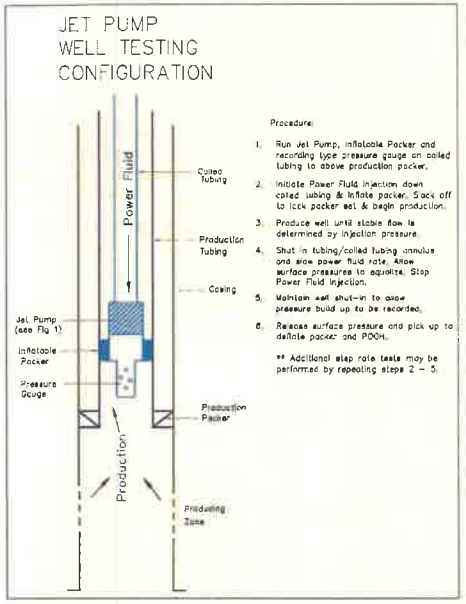

Fig. 3. By adding pressure gauges below a jet pump and using a simple operating procedure, operators can achieve downhole shut-in and minimize wellbore storage effects.

retrieval and replacement using slick line techniques.

Well Testing

By adding pressure gauges below a jet pump and using a simple operating procedure, downhole shut-in can be achieved to minimize wellbore storage effects in well test analyses. The schematic and steps for this type of test are shown in Fig. 3.

A resettable, three-packer inflatable straddle tool string can be used to perform multiple production tests during a single run into the wellbore (Fig. 4). This string can be run in cased hole or open hole and in vertical or horizontal wells. Within the limits imposed by allowable packer expansion ratios and well conditions, such tests may be performed as through-tubing operations.

In wells where completion interval length or horizontal lateral sections exceed 25% of vertical well depth, a modified straddle test tool should be run to be sure of optimum drawdown when conducting the uppermost test (Fig. 5). The simpler configuration of Fig. 4 continues to elevate pump depth as the work string is pulled to perform additional tests. This may require BHA trips to correct the pump depth spacing and optimize drawdown.

An example illustrates the efficiencies that can be gained. A New Mexico cased hole vertical well was tested in 11 individual perforated intervals in less than 24 hours. The testing was conducted using production tubing for power fluid input and a cementing pump truck for hydraulic power. Data were gathered using downhole recording pressure gauges and surface flow rate.

TABLE 1. NEW MEXICO WELL CONFIGURATION AND MULTIZONE TESTING INFORMATION

- Vertical well, cased hole.
- Intervals tested from 3,899 ft to 4,315 ft.
- 3½ in. tubing inside 7 in., 23 lb/ft casing.
- Weight-set packers in a three-packer straddle configuration.
- Power fluid input at 0.9 bbl/min. to 1.16 bbl/min., 2,200 to 4,200 psi surface pressure.
- Maximum production from individual intervals of 1.2 bbl/min.
- Produced fluid to surface in 1.6 hr.
- Average test time per zone of 2 hr.

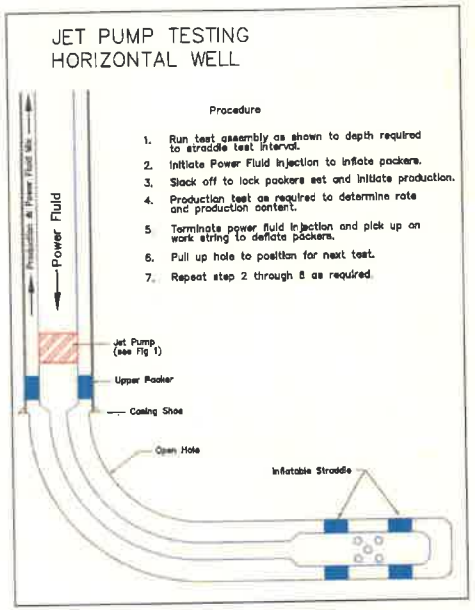

Fig. 4. A resettable, three-packer inflatable straddle tool string is used to perform multiple production tests during a single run into the wellbore.

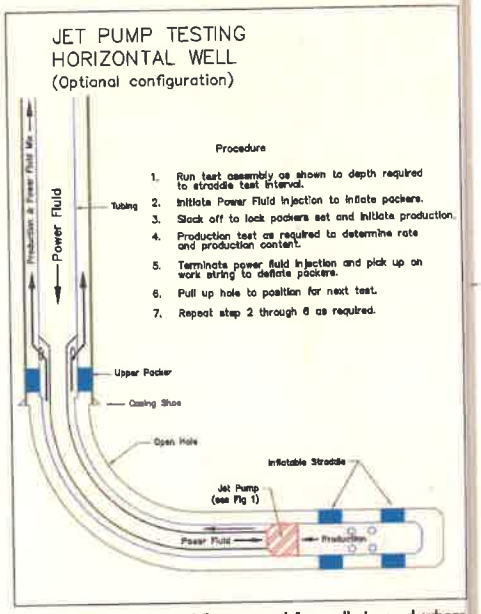

Fig. 5. A modified straddle test tool for wells is used where completion interval length or horizontal lateral sections exceed 25% of vertical well depth. Tool is run to be sure of optimum drawdown when conducting the uppermost test.

oil cut and total fluid recorders. The BHA was run and moved to the various test depths on production tubing.

Analysis of the test information identified high volume water producing intervals. A "scab" liner, using mechanical packers, was run to isolate them. Though no oil production increase resulted, water production was reduced by 6,800 b/d. The well production and average test information are shown in Table 1.

Offshore Artificial Lift

Productivity index must be verified before installing artificial lift. Many small one- to four-well offshore platforms may be candidates for artificial lift installation. However, limited recoverable reserves may not justify the cost of artificial lift using conventional workover operations. These completions can be tested using coiled tubing and a jet pump BHA. Tests for reservoir analysis and fluid production may be run with tools as shown in Fig. 3. Downhole recording pressure gauges may be added to the BHA for improved data accuracy.

Power fluid is input through coiled tubing with production returning up the annulus. Variations in volume and pressure can be used to perform step-rate production tests. If original estimates of productivity or BHP are incorrect, the jet pump can be reverse circulated to the surface and the mixing tube size changed.

Analysis of the well test data then determines actual reservoir conditions. If near-wellbore damage is revealed, an acid stimulation can be performed and the well again tested to confirm removal of damage and spent acids.

After well testing and data analysis, economic analysis can be conducted to determine the true economics of installing artificial lift. Several options are available using a jet pump.

The test BHA can be left in position, coiled tubing cut and hung off in the wellhead and production established. The power fluid pump used for testing can be left in operation or the well shut in until a properly sized power unit is installed.

Electric wireline can be used to:

- Perforate production tubing and establish communication with the annulus.
- Install a jet pump and isolation packoff (Fig. 6).
- Retrieve, resize and reinstall the pump.

Where necessary for safety reasons, the jet pump packoff assembly may be run with crossover housing to redirect power fluid and production mixture up the tubing ID and SCSSV.

Preliminary tests are being conducted on three wells using a coiled-tubing-conveyed jet pump BHA. Previous

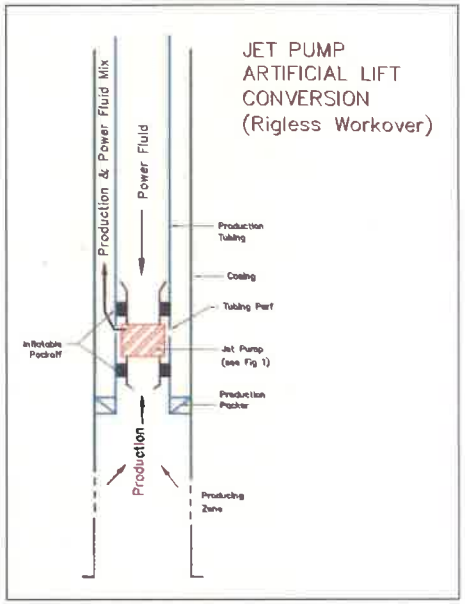

Fig. 6. The well completion option shows jet pump and isolation packoff installed by wireline.

BHA and PI data will be verified. Wells will then be converted to artificial lift with a jet pump isolation packoff assembly. Once production is established and stable for 2 months, more conversions are planned.

Increasing Production And Decreasing Operating Costs

In southern Argentina, wear from a sand-laden production stream was forcing operators to pull and repair hydraulic-powered reciprocating pumps at intervals averaging less than 3 months with about 35% of pulling operations requiring fishing.

In this environment a jet pump assembly has the potential to increase production and reduce costs. One well was selected for demonstration. With hydraulic fluid input of 250 b/d at 3,000 psi, the well was producing 112 b/d of 20° API crude with a 10% water cut. This is 9.7 bbl of fluid per hydraulic hp.

A jet pump was installed on 1¼ in. OD coiled tubing. With power fluid input of 550 b/d at 2,700 psi, the pump delivered 337 b/d of oil with a 12% water cut, 14.8 bbl of fluid per hydraulic hp. Power input requirements were twice that of the reciprocating pump, but the 3:1 increase in oil production more than offset power cost, yielding a reduction of 52% in power requirements per bbl of oil. A jet pump system has been in operation for more than 9 months without pulling.

TABLE 2. RESULTS OF CONTINUOUS PUMPING AT 95+% DRAWDOWN

	Daily production, bbl	Daily oil, bbl	Daily water, bbl
Day 1	60	18	42
Day 2	110	23	87
Day 3	230	92	138
Day 4	168	35	133
Day 5	296	120	176

Removal Of Near-Wellbore Plugging

In a remote Guatemala well, an unsuccessful acid treatment left the operator with suspected precipitates and production fines plugging the near wellbore region. Fluid entry on swab tests was less than 10 b/d.

A jet pump was positioned immediately above the perforations and operated to produce a 95% drawdown of static BHP. This was an attempt to produce the precipitates and fines. Results of several days continuous pumping are shown in Table 2. Interpretation of the test data showed that some plugging was removed from near the wellbore, but remaining severe formation damage limits daily production to less than economical. A small hydraulic fracture treatment is being considered to extend radially beyond the plugging and formation damage. This same technique can be used to produce at high localized drawdown across slotted liners to remove drilling mud plugging.

These examples show that combining jet pumps with other proved completion components in innovative designs can yield improvements in test data quality, production rates, and installation and operating costs. ●

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Permeability Profiles—Key To Reservoir Management

The ability to determine formation flow characteristics from well logs has long been sought after. Today's new technology provides encouraging answers that yield permeability profiling as the key to reservoir management.

hree-dimensional seismic data being collected routinely today offer those responsible for reservoir management a detailed picture of the configuration of the subsurface. Often, the porosity servoir rocks can also be deduced. However, knowing sity exists, i.e., that there is pore space and vugs for storage of hydrocarbons, is important but valueless if rocarbons cannot be made to flow into wells. neability is the quantity that measures flow capability. ng a permeability profile is the key to reservoir manent (Table 1).

able 2 lists the methods available for measuring permety. Accurate values can be obtained from cores taken ng drilling; however, cutting cores is expensive and s taken to the surface may be damaged or not represente of the reservoir rock of interest. Rotary coring can ide limited permeability data but, generally, insufficient are available to develop a permeability profile. Here, re concerned with measuring permeability with instruts placed in a well or used for logging a well. We shall ass permeability-measuring methods available from tern Atlas Logging Services (WALS). Together, they e it possible to obtain continuous permeability in any without coring or extensive well testing.

Wireline Permeability Profiles

There are three direct approaches to permeability determination from wireline logs: Magnetic Resonance Imaging Log (MRIL) nuclear magnetic resonance (NMR)-derived permeabilities, multipole array acoustic (MAC[SM]) Stoneley wave permeabilities, and reservoir characterization instrument (RCI[SM]) pressure transient-based permeabilities.

The oldest of the wireline methods for determining permeability, that of measuring the rate of pressure decay followed by the pressure buildup, now involves new tools and new interpretation techniques. The link of the RCI service permeability, which follows directly from Darcy's law, is more direct than that of the MRIL NMR-derived and MAC-based Stoneley wave methods. Although RCI pressure vs. time data provide only a limited number of permeabilities, they are ideally suited to calibrate or verify permeability profiles obtained from the MRIL and MAC services. Before giving details of the RCI, we will summarize the less familiar MRIL and Stoneley wave techniques

Undoubtedly the most significant advance in formation evaluation of the 1990s has been the introduction of reliable, laboratory-quality downhole NMR technology. The MRIL NMR-logging system is based on the unique gradient field technology introduced by the NUMAR Corp. The gradient field offers significant advantages over conventional homogeneous-field tools and permits both rapid and flexible NMR data acquisition. When the MRIL service is run in combination with conventional porosity and induction tools, formerly difficult formation evaluation problems are easily solved. Furthermore, MRIL data can be combined with MAC and RCI information to provide cost-effective calibrated permeability data.

Several of the MRIL outputs are relevant to the determination of producibility. The MRIL tool provides mineralogy-independent porosity. Recently introduced hardware and software permit complete characterization of the pore space. It is now possible to determine directly the volume of clay-bound water, the effective porosity, and the porosity available to moveable fluids. This capability has proven extremely beneficial, not only in the evaluation of low-resistivity formations that are easily overlooked when only conventional log data are evaluated, but also in the determination of flow eapacity.

The MRIL tool does not directly measure permeability and the interpretation of the data does not follow from Darcy's Law. NMR permeabilities are inferred from the decay of the echo amplitudes recorded at each depth. The echo amplitudes start at a maximum, the NMR porosity, and then monotonically decrease with time. Generally, the rate of decay of the echo amplitudes is a measure of the pore space's surface-to-volume ratio. However, the interpretation of the NMR echo decay may be complicated by multiphase saturation effects. Small pores have a large surface-to-volume ratio, while large pores have a small surface-to-volume ratio. By decomposing the recorded echo train into a number of underlying exponential decaying terms, the relative proportion of small and large pores can be determined. The NMR pore-size distribution data are the key to determining irreducible water saturation, moveable fluid saturation, and permeability. Generally, rocks with only large pores and small surface-to-volume ratios are very permeable, while rocks with mixed pore sizes are less permeable, and rocks with extremely small pores and high irreducible water saturations are tight.

It is easy to appreciate the value of NMR data for permeability determination. The key ingredients in computing permeability from thin sections are porosity, pore size, and pore connectivity. Conventional porosity logs provide only one of these three ingredients. NMR T_2 distributions provide a measure of the pore size. (T_2 is explained in the MRIL section of this article.) Thus, NMR permeability estimates are generally superior to permeabilities based on simple porosity-permeability correlations. However, if there is not a good correlation between pore size and pore connectivity, it is difficult to compute reliable permeabilities solely from NMR porosity and T_2 distributions. Fortunately, there is often a good correlation between connectivity, pore size, and porosity. Hence, especially in clastics, NMR-based per-

TABLE 1. APPLICATIONS OF PERMEABILITY PROFILES

Issues	Information
Average production rate	kH, PI
Injection/productivity index	PI
Recovery efficiency	Permeability variation
	Lorenz coefficient, Dykstra-Parsons coefficient
Vertical communication	k_v/k_H
Production optimization–completion strategy	Perforation placement/flow profile modification
Production optimization–waterflood strategy	Manage sweep efficiency

TABLE 2. METHODS FOR MEASURING PERMEABILITY

- Well and drillstem tests
- Wireline formation testers (RCI and FMT)
- Conventional cores
  - Whole core
  - Core plugs
  - Probe permeameters
- Sidewall cores (rotary - RCOR)
- Wireline logs
  - NMR (MRIL)
  - Stoneley waves (MAC and MAC II)

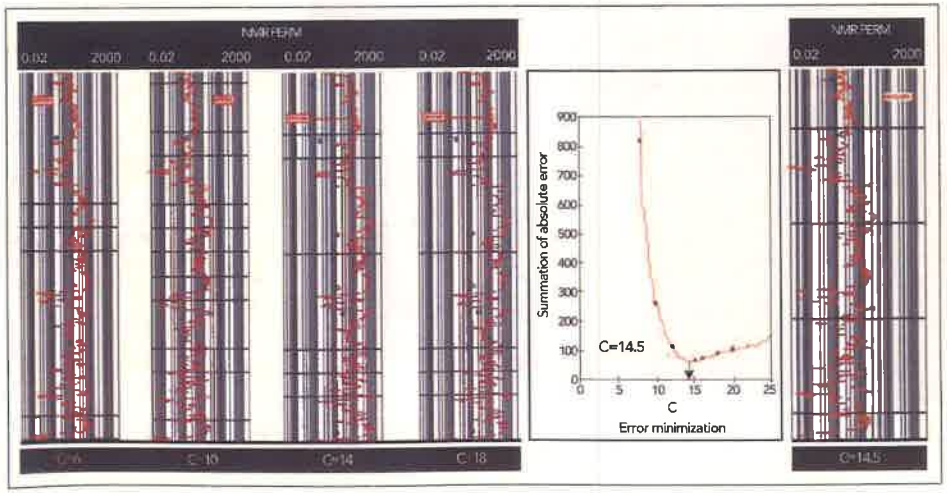


Fig. 1. RCI permeabilities and permeability profiles for different values of C—Permeability is indicated by yellow ellipses.

by D. Georgi, E. Kasap, X. Tang and A. Cheng, Western Atlas Logging Services

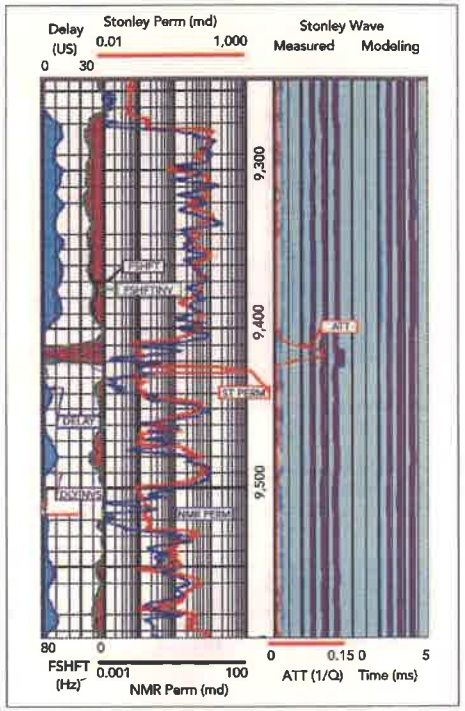


Fig. 2. Permeability profiles from MAC and MRIL.—Note that the permeability scales for the MAC and MRIL differ. No attempt was made to normalize the two data sets.

meability estimates are reliable.

The Coates equation, given and explained later in the MRIL section of this article, has been used successfully to compute permeability from MRIL data for many formations. The constant, C, in the Coates equation may be formation specific. When core (conventional or rotary sidewall) data are available, it is a relatively straightforward procedure to adjust C to obtain a match of the NMR and core permeabilities. However, core data are often not available and other means of calibrating the NMR-based permeabilities are required. Pressure-transient permeabilities, derived from either RCI or formation test data (see later section), provide a means for determining the value of the constant C. This source of permeability calibration data is particularly attractive as it is an effective, in-situ permeability fundamentally linked to the Darcy equation.[1] Shown in Fig. 1 are the RCI permeabilities and the permeability profiles computed with different values of C for a North Sea well. Also shown is a plot depicting the error minimization procedure used to determine the optimum value for C.

The analysis of Stoneley wave logs is another means for determining permeability and permeability profiles. As with the formation test permeabilities, the derived permeabilities are related to fluid movements and pressure perturbations and can be derived from first principles. Early theoretical work[2,3] established the connection between permeability and Stoneley wave attenuation and velocity. Both laboratory[4] and field observations[5] demonstrated the connection between formation permeability and Stoneley wave properties. Unfortunately, other factors contribute significantly to the Stoneley wave velocity and attenuation and must be fully accounted for if permeability is to be estimated from these logs. Meaningful inversion of measured Stoneley wave properties required the development of simplified theories[6,7] and fast computational methods.[8] The inversion process accounts rigorously for purely elastic effects and borehole diameter changes and it simultaneously forward-models both the velocity and attenuation of the Stoneley wave.

In Fig. 2, both Stoneley wave and MRIL permeabilities are shown. There is good correlation in the permeability profiles; however, an order of magnitude difference in the permeability values exists. The MRIL permeabilities were computed with the Coates equation and the constant C (equal to 10) was not adjusted and no effort was made to adjust the Stoneley wave permeabilities (transmissibilities) by varying the assumed formation fluid parameters (density, viscosity, and acoustic velocity).

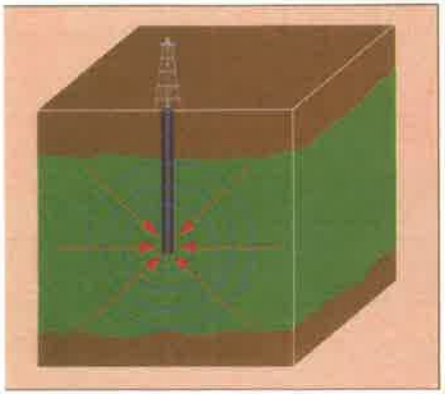
By combining the RCI, NMR, and Stoneley wave permeabilities, it is possible to obtain calibrated permeabilities and separate contributions to permeability arising from the matrix and fractures.

Permeability From Wireline Formation Test Pressure Transient Data

Since the introduction of wireline formation testers, service companies and clients have attempted to infer permeability from the behavior of the pressure-transient data. Originally, these tools were designed to obtain formation fluid samples and measure formation pressure, P*. Tools were not optimized for permeability determinations. In permeable formations, the buildup occurs so quickly that no meaningful transient data can be collected, while in very tight formations, pressure buildups are small and often dominated by wellbore, temperature, and storage effects. Tools designed with permeability determination as a goal provide high-quality data that can be interpreted for permeability.

The RCI tool is an example of an advanced generation formation test tool available to the industry. It uses pumps that obtain high quality samples and allow repeat pressure transient measurements without resetting the probe, permitting the direct verification of the pressure transient data. The RCI tool also monitors pump piston movement, information that is required to compute a more precise flow rate for permeability calculations.

Conventional interpretation techniques, which were borrowed from conventional well testing for wireline formation pressure transient analysis (Figs. 3 and 4), are inappropriate. It seemed natural to borrow interpretation technology from the well test arena, given the vast body of



g. 3. Spherical-flow analysis assumes fluid flow between two herical surfaces.

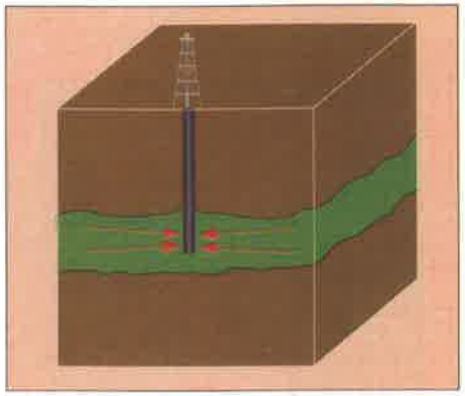


Fig. 4. Cylindrical flow analysis assumes fluid flow between two flat bounding surfaces.

nowledge available for well test interpretation. However, essure-transient technology available for core analysis[9] is ore appropriate for downhole formation test interpreta- on than are conventional well test methods. In coopera- tion with the University of Tulsa and the Oklahoma Center for Advancement of Science and Technology, WALS developed a new, modified hemispherical flow analysis technique.

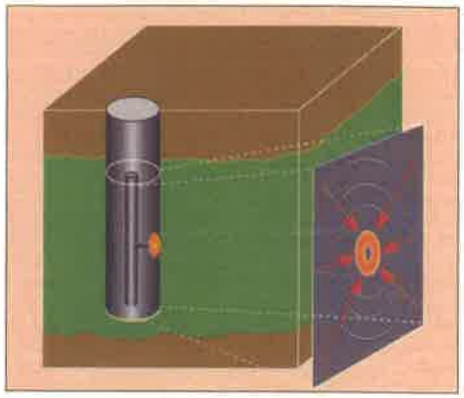


Fig. 5. Flow restricted by a probe on a wellbore is created in semihemispherical domain.

Drawdown and buildup analysis have generally been treated as separate tests. In fact, many reasons have been proposed to explain the differences between the results of the drawdown and buildup analysis. Modified hemispherical-flow analysis can be extended by following standard material balance considerations to apply to both the drawdown and buildup tests (Fig. 5).[10] From the combined drawdown and buildup, Formation Rate Analysis (FRA) permeability, or, to be more precise, k/μ (e.g., mobility), original pressure P^*, and system compressibility are calculated. FRA combines the drawdown and buildup data into a single plot where both the drawdown and buildup periods are well represented by straight lines with identical slopes.

FRA follows from the considerations of the fluid flowing into the tool and the change in internal volume of the tool. With FRA, it is not necessary to determine the onset of a particular flow regime. The analysis can be applied to the drawdown and buildup analysis and generally fits the entire observed pressure range. In Fig. 6, pressure vs. the formation rate for a repeat RCI pressure test is shown. The entire test, from a minimum drawdown pressure of 3,750 psi to the maximum buildup pressure of 4,633 psi, is well characterized by a single straight line. The same data are plotted vs. the cylindrical time function in Fig. 7 and the spherical time function in Fig. 8. Only 2 psi of the observed pressure data fit the predicted straight-line relationship of the cylindrical and spherical-flow analysis, clearly demonstrating the inappropriate application of cylindrical and spherical flow analysis to wireline formation test data.

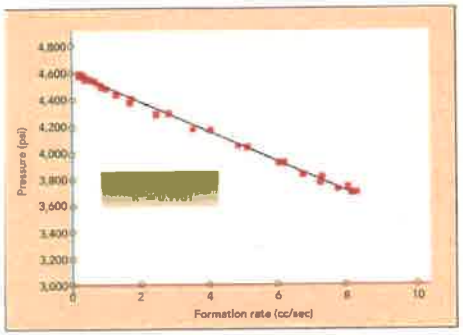


Fig. 6. Pressure from an RCI repeat test vs. formation rate and the best fit straight line—Both drawdown and buildup data are used to compute the mobility, 13.46 md/cp, from the best fit straight line.

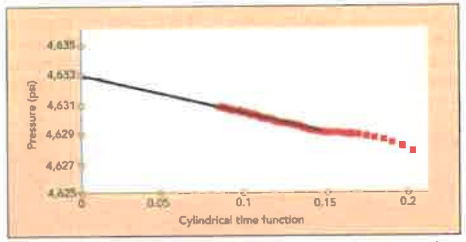


Fig. 7. Pressure vs. cylindrical time for same data plotted in Fig. 6—Only 2 psi of the buildup data can be fit with a straight line and the resulting mobility, 23.6 md/cp, is unreliable.

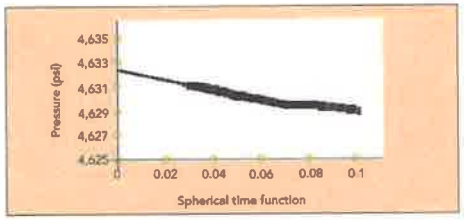


Fig. 8. Pressure versus cylindrical time for same data plotted in Fig. 6—Only 2 psi of the buildup data can be fit with a straight line and the estimated P* and mobility are unreliable.

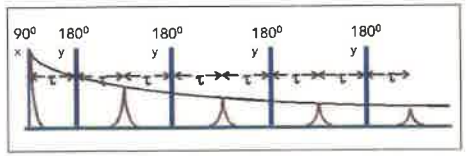


Fig. 9. The schematic is of Carr-Purcell-Meiboom-Gill pulse-echo sequence.

Permeability From NMR Relaxation Data

The NMR signal amplitude is proportional to the hydrogen proton density. Most hydrogen in reservoir rocks is associated with oil, gas, and water. The hydrogen that may be part of the rock matrix relaxes so quickly that it is invisible to wireline NMR tools. Therefore, the NMR signal, when properly calibrated, is proportional to porosity.

Only a few years after the laboratory verification of the nuclear magnetic resonance phenomenon, oil industry researchers realized the potential usefulness of NMR measurements for formation evaluation. Early tools relied on the earth's magnetic field to align the hydrogen protons. Because of electronic limitations, it was not possible to collect data at acquisition times of less than 25 milliseconds (ms). The accepted interpretation methodology called for the data to be projected to time zero. Amplitude, scaled in porosity units, was dubbed the free fluid index, based on a good correlation between laboratory-determined irreducible water saturations. Interest in NMR was primarily driven by theoretical studies[11] and laboratory work[12,13] that demonstrated the potential for inferring permeability from relaxation data.

Modern NMR tools utilize a Carr-Purcell-Meiboom-Gill pulse sequence to collect a time series of echoes (Fig. 9). The rate of decay of the echo amplitudes is a measure of the pore space's surface-to-volume ratio. Small pores have a large surface-to-volume ratio, while large pores have a small surface-to-volume ratio. Typically, pores in real reservoir rocks vary in size; hence, the NMR echo signal is the superposition of decay rates associated with the different size pores. By decomposing the recorded echo amplitude data into a number of underlying exponentially decaying terms, the relative proportion of large and small pores is established. This pore-size distribution is the key to determining irreducible water saturation, moveable fluid saturation, and permeability.

There are two commonly used approaches for computing permeability from NMR data. Both approaches ultimately depend on the T_2 distributions. In NMR experiments, it is important to differentiate between spin-lattice and spin-spin relaxation (T_1 and T_2, respectively). However, for this discussion it suffices to note that T_1 is always greater than T_2 and that, experimentally, it has been found that the ratio of T_1 to T_2 at 2 MHz is 1.65 ± 0.2.[14] For the purposes of this paper, we will not differentiate between the two relaxation mechanisms.

One approach builds on the observation that rocks with high irreducible water saturations generally have low permeability. The Coates equation uses the ratio of the moveable to bound fluid saturation and the porosity, where the moveable and bound fluid saturations are derived from the T_2 distributions,

$$(1)\quad k[md] = \left(\frac{\phi}{C}\right)^4 \bullet \left(\frac{MBVM}{MBVI}\right)^2 .$$

Here, k is permeability in millidarcies, ϕ is the porosity in percent, and MBVM and MBVI are the MRIL bulk volume moveable and bulk volume irreducible fluids, respectively. The constant C is often taken to be 10, which works well in the Gulf Coast, but is formation specific and may need to be

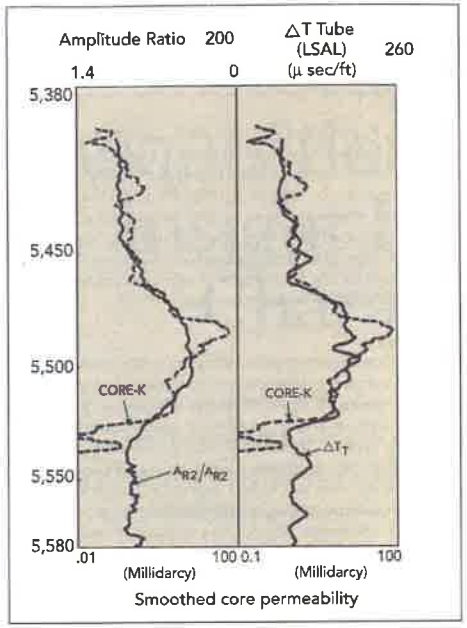


Fig. 10. Comparison of core permeability and Stoneley wave slowness and amplitude ratio data.[5]

adjusted to obtain a good match to core permeability.

In addition to the scaling constant C, the Coates equation relies on the separation of the moveable and irreducible fluids. Generally, the separation is affected by choosing a T_2 cutoff value. It is assumed that the water in pores with T_2 values less than the T_2-cutoff value cannot be produced and is irreducible, while the fluids in pores with T_2 values greater than the T_2-cutoff value are moveable.

The other approach can be derived from dimensional analysis or from the Kozeny-Carman equation. T_2 distributions are derived from the echo data and can be related to the surface-to-volume ratio, which can be further interpreted as pore-size distributions.

The Kozeny-Carman equation can be rewritten in terms of the NMR relaxation time,

$$(2)\quad k = \frac{1}{8}\phi\,\frac{(\rho F_s T)^2}{\tau^2}$$

$$k \propto \phi\,\rho^2\,T^2 .$$

where ρ is related to relaxation processes occurring at the pore surface, F_S is a constant relating to characteristic length of a pore to the surface-to-volume ratio, and t is a dimensionless measure of tortuosity.

This is the same result that was obtained and verified by Seevers[11] for water-saturated quartz powders. The same equation also follows from dimensional analysis, which might explain why others have estimated permeability using the previous equations with different exponents of porosity[14,15]. Kenyon[15] found predicted permeabilities to be slightly better when porosity was raised to the fourth power. They argued that this might be attributable to the difference between the pore-throat and pore-body radius. However, generally in clastics, the pore throat, pore body, and grain size are all linearly related. Therefore, it is more reasonable to assume that an independent parameter Γ exists, which is the ratio of the pore-throat to pore-body radius, raised to the same power as the relaxation rate,

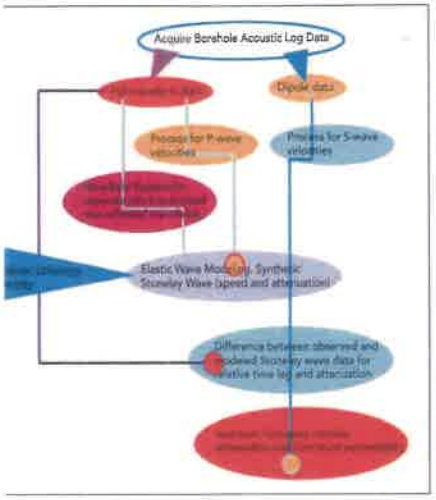
$$(3)\quad k \propto \phi\,\rho^2\,\Gamma^2\,T^2 .$$

The constants ρ, Γ, and other factors, including the shape factor, F_S, cannot easily be determined independently and are best lumped and treated as a single formation-specific constant—a constant that needs to be determined from some other measurement or core analysis.

Permeability From Acoustic Log Data

Full-waveform acoustic logging tools measure formation velocities by transmitting and receiving pressure pulses. The MAC tools (MAC and XMAC[SM] [Cross-Multipole Array Acoustilog]) provide measurements of both the body-wave compressional and shear velocities and the guided Stoneley waves. Stoneley waves are propagated along the borehole interface. The MAC tools, which carry both compressional and shear-wave sources, were especially designed to preferentially excite low-frequency acoustic waves. From the decay or attenuation of the low-frequency pressure pulses, it is possible to estimate the permeability. Compressional and shear wave velocities and attenuation data are obtained from the conventional full-waveform and dipole data. (A dipole source or receiver preferentially emits or receives in two opposite directions. The MAC tool has both conventional and dipole sources and receivers.) The Stoneley (or tube) wave is ideally suited for permeability estimation. Early work by Rosenbaum[3], based on the original work by Biot[2], recognized the potential to extract permeability from acoustic data. However, that work discouraged many workers because it focused on frequencies common at that time in acoustic logging tools (20 kHz) and assumed mud cakes to be rigid and impermeable. Under those assumptions, the effects of permeability on the acoustic wave data are exceedingly small and would not be detectable.

In 1984, Mobil published the first convincing examples of permeability derived from Stoneley wave data[5] (Fig. 10). Mobil was successful because its tool was able to generate and respond to extremely low-frequency (1-2 kHz) Stoneley waves. At such low frequencies, it was easier to measure the amplitude and velocity of the Stoneley waves. Also, the permeability effects on the amplitude attenuation and velocity are much greater than at high frequencies. Further, Mobil's data indicated that the mud cake had a minimal impact on the Stoneley wave properties.



11. Acoustic data processing for permeability.

The Mobil data renewed interest in estimating permeability from Stoneley wave measurements. The ssachusetts Institute of Technology (MIT) Borehole ıustic and Logging Consortium became one of the most ive research groups in this area. During the next 10 rs, the MIT consortium significantly advanced the ustry's understanding of the low-frequency Stoneley ves and developed sophisticated numerical methods that ıwed both rapid and accurate forward modeling.

Forward modeling allows for the separation of the dominant elastic and borehole geometrical effects from secondary dynamic permeability effects. It is crucial to include borehole rugosity and the layer-to-layer changes in elas- properties in order to accurately model the attenuation l velocity of the Stoneley wave.[16] Once these changes are ounted for, the data must be separated into downgoing l upgoing reflected waves to account for changes in ve amplitude associated with interference effects of the ected and transmitted waves. Wavefield separation and forward modeling make it possible to account for the ersion (change in wave speed) and attenuation (change wave amplitude) that are unrelated to the formation permeability.

The final step in estimating permeability from the neley wave data is to account for intrinsic attenuation ociated with formation and borehole fluids. These :cts also impact the Stoneley wave amplitude attenuaı and velocity dispersion. Because the intrinsic attenuaı has a different effect on the wave propagation than s the permeability, it is possible to estimate simultaneıly the formation permeability and the intrinsic attenuaı.

The permeability-related Stoneley wave attenuation and dispersion are approximately controlled by the following parameter combination:

$$(4)\quad \frac{k}{\mu v_o (P_o)^{1/2}},$$

where μ, P, and v are the pore fluid viscosity, density, and velocity, respectively. Other relevant parameters can be obtained from log data (Fig. 11). However, the pore fluid parameters may be difficult to estimate, given the unknown saturation states in the sensitive volume (e.g., connate water, hydrocarbons, and invaded drilling fluids). The effects of these pore fluid parameters can be accounted for by calibrating the Stoneley wave-derived permeabilities with those from other measurements.

Summary

New tools and interpretation techniques now make it possible for reservoir geologists and engineers to describe and manage reservoirs better. With the widespread availability of these tools, it is now possible to obtain continuous permeability profiles on any well without coring or extensive well testing. The continuous permeability profiles obtained from wireline logs are ideally suited for reservoir description and reservoir management. Permeability profiles allow geologists and reservoir engineers to quantify heterogeneity and tailor completions to maximize recovery rate and efficiency. ●

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Multicomponent Seismic Acquisition Brings A New Insight Into Reservoir Characterization

Amoco's recent decision to carry out a 100-km², four-component (4C) survey in its North Sea Valhall field represents a landmark for the seismic industry. Contractor Geco-Prakla said that the project is the biggest to date and will be the toughest test yet of the economic impact of offshore multicomponent acquisition. *Petroleum Engineer International* interviewed Dr. Olav Holberg, head of Geco-Prakla Reservoir Characterization and Monitoring, to find out how he views the future of this new technology.

Olav Holberg is excited when he talks about the potential of 4C seismic technology. He thinks that the technique will help to bring seismic data to the fore in all key management decisions, from exploration right through to integrated reservoir optimization. "The technology is still in its infancy, but I believe it will have as big an impact as the move from 2-D to 3-D seismic acquisition in the 1980s," he said.

Experience accumulated from 26 4C acquisition projects in the North Sea over the past 2 years (Fig. 1) has already convinced Holberg and his team of the value of opting for seismically driven reservoir characterization using multicomponent data. "Multicomponent acquisition has great potential—both by itself and as an important element in 3-D time-lapse monitoring," he said.

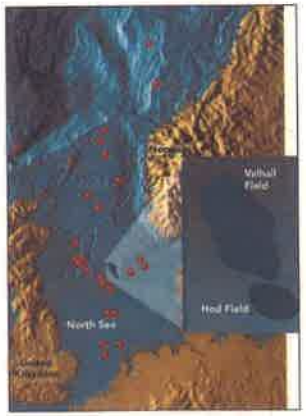


Fig. 1. The map of the North Sea shows the Valhall field and other Geco-Prakla 4C projects carried out since 1996.

"In essence, 4C seismic is providing a new way of looking at reservoirs," Holberg explained. "Shear wave data allow us to determine reservoir characteristics and features that were impossible to decipher using conventional compressional (P) wave data analysis only."

Table 1 shows the range of objectives behind the 26 multicomponent surveys Geco-Prakla has carried out in the North Sea. The technology has proven to be particularly applicable in fields where the reservoir is obscured by gas chimneys. The results also look positive for imaging low-impedance-contrast reservoirs that are not clearly visible on conventional data. Such reservoirs display a very small contrast in acoustic impedance between the reservoirs and the caprock, but can have large contrasts in Vp/Vs ratio and Poisson's ratio (Fig. 2). Because con-

by **Garry Charnock, TeS, Chester, UK**

TABLE 1. THE OBJECTIVES OF GECO-PRAKLA'S MULTI-COMPONENT SURVEYS IN THE NORTH SEA SINCE 1996 (SOME SURVEYS HAD MORE THAN ONE OBJECTIVE).

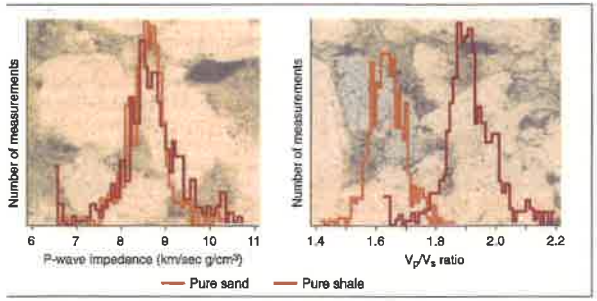
No. of projects	Objective
7	See through gas invaded zones
3	Image beneath multiple gas reservoirs
5	Discriminate between sand and shale
4	Map low-impedance-contrast reservoirs
4	Quantify P-P anomalies
3	Map saturation between wells
2	Map the OWC
1	Sub-salt investigations
1	Sub-basalt investigations

itional P-wave data are predominantly sensitive to changes in acoustic pedance, whereas converted S-wave S-wave) data are more sensitive to nges in Poisson's ratio, 4C data can p image low-impedance-contrast mations. Recent tests demonstrate the improved mapping of low-pedance-contrast reservoirs have to another full field-wide 3-D multomponent survey which is due for npletion in May 1998. The 4C technue also has major potential for disminating between lithology and d effects in the data, and for mapg saturation and reservoir proper- between wells.

w Applications

cording to Geco-Prakla, the jury is l out on the usefulness of multinponent surveys for mapping fracdensity and orientation and for estigating subsalt and sub-basalt. company is studying ways of nparing P- and S-wave data to proa more accurate method of imaging beneath salt. Salt layers cause a problem in conventional seismic surveys because they are strong mode converters: they convert most of the P-wave energy into S-waves, and this results in poor P-wave imaging. By comparing the recorded P-and S-waves, Geco-Prakla hopes that it may be possible to determine the base of the salt layer and to see beneath salt horizons. The company has just embarked on a series of new surveys in the Gulf of Mexico where it hopes to learn more about the applicability of shear wave data in subsalt imaging.

Shear waves travel more slowly than compressional P-waves because they propagate by a sideways particle motion. This sideways propagation of shear waves means that they cannot pass through, or be distorted by, fluids. This fundamental difference between P- and S-wave motion is very useful. In a conventional P-wave survey, the compressional wave motion is affected by the fluids in rock pores. In some situations, for example when trying to investigate reservoirs that sit below escaped gas clouds, the P-waves can be so distorted and attenuated that they cannot provide any clear structural information about the subsurface.



. 2. Distribution of acoustic impedance and Vp/Vs ratios are shown for pure ɔlogies in three wells in a North Sea field.

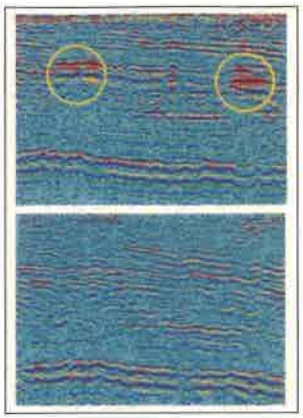


Fig. 3. P-section (top) and equivalent S-section (bottom). Two distinct amplitude anomalies can be identified on the P-section but are not present on the S-section. Because P-waves are sensitive to fluids, and S-waves are not, these anomalies are expected to be fluid effects: one anomaly is a proven gas field.

Shear waves, on the other hand, are affected only by the rock matrix and give supplementary information on the characterization of the subsurface. These new data can be compared with compressional wave data, giving a new insight into the reservoir. This distinction is extremely valuable in all 3-D and 4-D surveys. Shear wave data also look set to provide a reliable method of mapping lithology changes. Operators are often enticed to drill toward bright spots on seismic sections, only to discover a harder rock type rather than gas or oil. Shear waves provide a method of checking whether the bright spot is caused by fluid or by lithology effects. If gas is present, it should be seen only on the P-wave section, not on the S-wave data (Figs. 3 and 4).

In conventional 3-D time-lapse seismic surveys, P-wave seismic acquisition is carried out to monitor saturation and reservoir pressure variations over time. Geophysicists currently attempt to map fluid distribution changes across a producing reservoir (Fig. 5), predominantly on the basis of how acoustic impedance has changed between surveys. However, if a field has not been subjected to a proper preproduction baseline survey (when the oil–water contact (OWC) is normally well behaved), a conventional time-lapse survey may prove to be unreliable. The problem stems from the porosity–saturation ambiguity in acoustic impedance. It is difficult to use acoustic impedance alone to distinguish between a predominantly oil-saturated area and a water-saturated area with higher porosity.

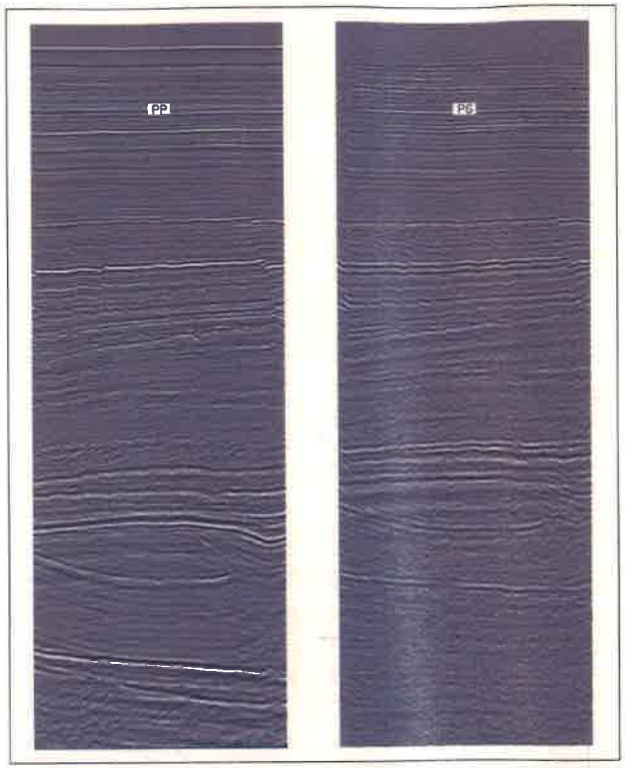


Fig. 4. The introduction of PS-wave data (right) is offering a new method of extrapolating lithology and pore fluid information away from the well. PP reflectivity data (left) contain information on acoustic impedance, whereas PS-wave data are influenced by Poisson's ratio. This means that it is now possible to have PP-wave data along a formation of interest and compare these to PS reflectivity for the same formation. This allows a quantitative assessment of the two data sets, reducing ambiguity and improving fluid mapping reliability. The success of this process depends on proper well calibration.

This linking of 4C and time-lapse 3-D (4-D) data will have major importance. Recent work by Geco-Prakla has indicated that a large proportion of all the North Sea fields could benefit from reservoir characterization studies involving 4-D surveys (Fig. 6). The added clarity and reduced interpretation ambiguity provided by 4C data will no doubt strengthen the arguments for using this new technology. Fig. 7 compares the quality of P-wave data acquired by conventional 3-D streamer with those from a MultiWave Array system where the latter were acquired during adverse weather when no conventional towed streamer acquisition would have been feasible.

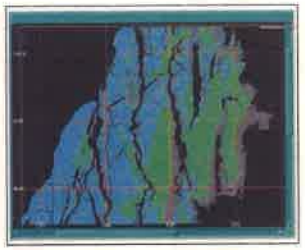


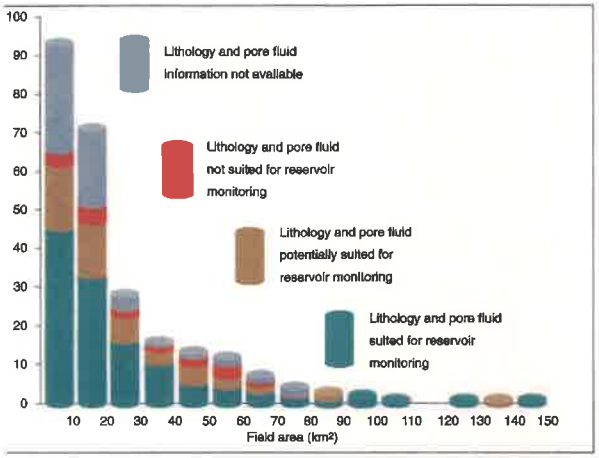
Fig. 5. An example of fluid mapping from the North Sea Gullfaks field, uses data acquired and processed by Geco-Prakla. (Image courtesy of Statoil.)

Quality And Cost

Holberg stressed the importance of acquiring high-quality, repeatable surveys for all 4-D work. The more subtle the changes in seismic response are, the higher the quality of the seismic investigation needs to be, and this is a strong incentive for seabed receiver systems. The key factor here is the quality of seabed recording. Cable and sensor design can be critical, but with the right equipment, the geophone response exceeds that of hydrophones.

According to Geco-Prakla, seabed data acquisition has several other advantages over towed streamers, in addition to simply facilitating PS wave recordings. For example, fixed receiver locations improve the repeatability of surveys; the need for infill shooting is eliminated; ambient noise levels are lower; higher bandwidths are possible; operations are less susceptible to bad weather (Fig. 8); and acquisition geometry is more flexible.

The industry is currently taking a long, hard look at the cost of multicomponent surveys. Operators are wondering whether it is worth paying



. 6. North Sea fields are divided by size, lithology and suitability for time-lapse nitoring.

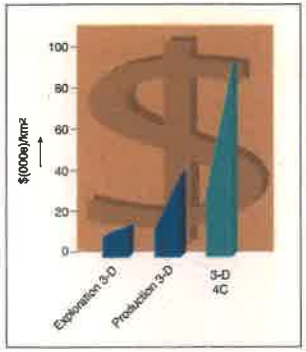


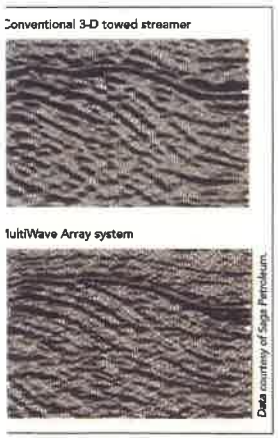
Fig. 9. Seismic survey costs vary according to survey size, data density, offset requirements and environmental factors: the sloping top of each column indicates the current range of costs of each type of seismic acquisition. Small production surveys cost more than large exploration surveys.

ra for the retrievable or permanent bed acquisition systems necessary record shear waves. Cost comparns between various survey types pend on several factors (Fig. 9). Multicomponent surveys are generally more expensive for exploration 3-D but can be highly cost effective for smaller production 3-D surveys. Also, for a given field size and water depth, multicomponent seabed survey costs can vary by as much as a factor of three, depending on requirements for maximum and minimum offsets.

As a general guide, the seismic acquisition cost per square kilometer of image area depends on several factors: image area (survey size), data density (bin cell size and fold), minimum and maximum source–receiver offset requirements, and surface and seabed obstructions. Different techniques depend on these factors in different ways, so gross generalizations are difficult to make.

Smaller image areas and obstructions at the surface can make conventional and high-density towed marine acquisition operationally less efficient. In such cases, data acquisition based on retrievable or permanently installed receiver arrays is a cost-effective alternative. Permanently installed systems are particularly attractive for frequent monitoring of limited areas of a field, such as in the close monitoring of critical injection processes.

"As an industry we have yet to realize the full potential of 4C seismic technology," Holberg said. "But by the year 2005 this is likely to be the preferred technique for routine 3-D/4-D production geophysics, and will also be used selectively as a predrilling 3-D exploration tool." ●



7. The section on the top shows data ained in the North Sea using conven- al towed streamers. There is a striking rovement in P-wave data quality ained from the MultiWave Array sys- (bottom). The target depth is approxi- ely 3.5 km.

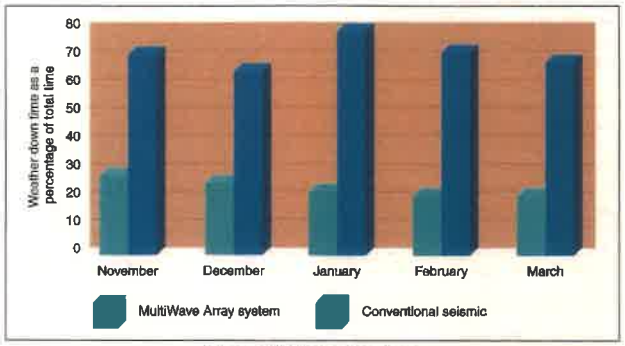


Fig. 8. Recent statistics from Geco-Prakla winter operations in the North Sea demonstrate the robustness of 4C acquisition using the NESSIE 4C MultiWave Array system.

Marine 3-D Data Acquisition Techniques

Currently available and emerging techniques for 3-D seismic data acquisition include:

- Conventional towed streamer.
- Conventional ocean-bottom cable (OBC).
- Multicomponent seabed data acquisition.
- Seabed data acquisition using permanently installed receiver arrays.

The introduction of multistreamer operations has made conventional marine data acquisition a very cost-effective technique, particularly for large exploration surveys. Also, developments in source, streamer and navigation technology during the past 15 years have dramatically improved 3-D seismic data quality.

Compared with conventional marine acquisition and independently of the use of multicomponent sensors (Fig. A1), seabed data acquisition offers the following generic advantages:

- Receiver locations remain constant during shooting–this eliminates any data smearing due to varying and uncertain receiver positions, and also effectively eliminates the need for infill shooting.
- Acquisition geometry flexibility–facilities can be undershot more easily and true 3-D geometries can be designed that will ensure target illumination from all directions.
- Potential for higher bandwidth–moving the receivers down to the seabed in deep water or the combined use of hydrophone and geophone data essentially eliminates wavelet smearing due to the receiver surface ghost.
- Less ambient noise–generally the acoustic noise level is lower at the seabed than at the surface.

Furthermore, the use of permanently installed seabed receiver arrays will provide certainty in the repeatability of the receiver positions from survey to survey (Fig. A2).

The use of wells as calibration points is also critical to the success of seismic reservoir monitoring. Well calibration is needed to establish a relationship between reservoir parameters and the observable seismic parameters and to constrain the interpretation of each time-lapse data set. VSP data and well logs should be used to calibrate the seismic response. Pressure and resistivity sensors are needed to calibrate the fluid front locations.

New, innovative software has been developed to compute and manipulate seismic attributes and to use these attributes to classify and map reservoir properties. This tool kit is now helping to reveal reservoir structure and properties far away from any wells.

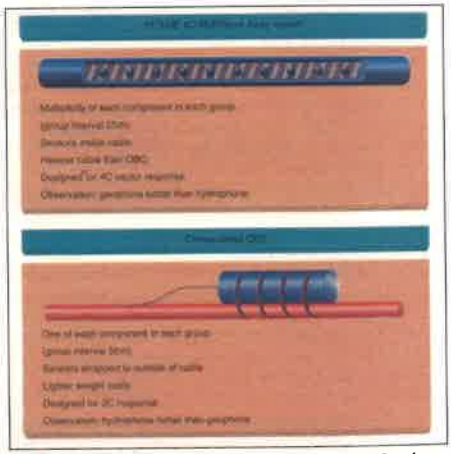


Fig. A1. The NESSIE* 4C MultiWave Array* system has been specifically designed to give good 4C vector response. Unlike the conventional ocean-bottom cable (OBC), which has externally mounted geophones, the NESSIE 4C MultiWave Array system includes sensors within a heavy cable. Geco-Prakla claims that this improves the data quality and consistency.
(*Mark of Schlumberger)

Fig. A2. Hydrophone cables laid in position on the seabed over Foinaven Field, west of Shetland. To make sure that strong currents did not move the cables (which would have affected the repeatability of the survey), they were buried in a seabed trench that was dug using a water jet from a remotely operated vehicle—technology routinely applied to transoceanic power and telecommunications cables.

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StarWars Technology May Revolutionize Natural Gas Drilling

The Gas Research Institute, the U.S. Air Force and the U.S. Army are teaming up to determine whether StarWars laser technology can be used to drill natural gas wells.

A 2-year basic research project will examine the feasibility, costs, benefits and environmental impact of applying laser technologies to drill and complete wells. An improved understanding of laser applications could lead to the development of several products, including a downhole laser drilling machine, laser-assisted drill bits for both conventional and coiled tubing applications, a laser perforating tool and sidetrack and directional laser drilling devices.

"Laser technology has the potential to revolutionize gas drilling in the 21st century," said Richard Parker, GRI principal technology manager of basic research. "Achieving a technological breakthrough with laser drilling could generate the kind of radical change that occurred at the turn of this century when the rotary drill replaced cable tools."

GRI will manage the project, and the Colorado School of Mines (CSM) will be the primary contractor. Subcontactors are Solutions Engineering of Lakewood, Colo.; Massachusetts Institute of Technology and Phillips Petroleum Co.

Objectives

The laser drilling consortium has five primary objectives:

- Determine the amount of data available on StarWars laser technologies.
- Evaluate the capabilities and limitations of applying lasers to drill and complete gas wells.
- Decide what areas of laser drilling research need to be addressed.
- Quantify benefits that can be obtained from laser drilling, such as higher penetration rates, reduced rig day rates and casing requirements, and improved safety and economics.
- Undertake laboratory research to understand laser, rock and fluid interactions.

The military's participation is in response to a congressionally mandated technology transfer program to leverage Cold War defense investments in ways that enhance U.S. industrial and technological competitiveness.

"The Army at HELSTF (High Energy Laser Systems Test Facility) is proud to support the U.S. gas and oil drilling industry by helping transfer our laser technology to their rock drilling applications," said Russ Alexander, technology transfer manager at the Army Space and Missile Defense Command.

The research will include tests of several laser systems at the U.S. Army's HELSTF, White Sands Missile Range, and at the Air Force Research Laboratory's Directed Energy Directorate at the Phillips Research Site, Kirtland AFB, N.M. The petroleum engineering department laboratories at CSM will be used to determine porosity, permeability, mineralogy, strength, elastic and mechanical properties, and pore-size distribution of target samples.

The potential benefits of laser drilling include increased rate of penetration, reduced or eliminated rig dayrates and enhanced well control, perforating and sidetracking capabilities. Bit wear, tripping in and out of the hole, and multiple casing strings may become things of the past.

Laser is an acronym for Light Amplification by Stimulated Emission of Radiation. Laser devices basically convert energy to photons that can be focused into intense beams to fragment, melt, fuse or vaporize rock,

Staff Report

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Fig. 1. Dr. Keith A. Truesdell of the Air Force Research Laboratory's Directed Energy Directorate works on a Chemical Oxygen-Iodine Laser (COIL). This laser technology was used aboard the Airborne Laser.

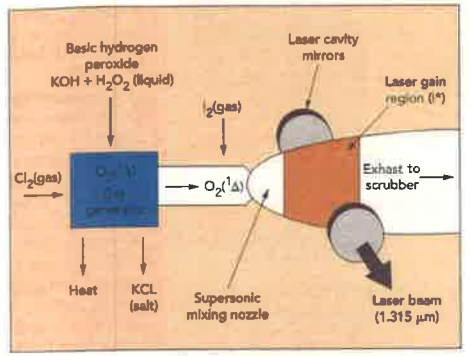


Fig. 2. In the Chemical Oxygen-Iodine Laser, chemical reactions produce excited oxygen, which dissociates and excites molecular iodine, which lases.

depending on input power.

Two promising high-energy lasers will be used in testing advanced drilling concepts:

- **Mid Infrared Advanced Chemical Laser** (MIRACL)—The highest average power laser (megawatt class) in the United States was originally developed for shipboard defense and used extensively for testing StarWars concepts during the 1980s and 1990s at HELSTF. The existing MIRACL laser has propagated hole-burning power many miles through the atmosphere at flying tactical and strategic military targets, and has the demonstrated power levels needed to burn through solid materials such as soft rock minerals.
- **Chemical Oxygen-Iodine Laser** (COIL)—This high-powered laser invented by the U.S. Air Force in 1977 for air-to-air defense appears to offer potential for natural gas drilling applications. COIL has gained notoriety as an airborne laser tactical weapon capable of tracking and destroying missiles (Fig. 1). This same precision applied to drilling and completing gas wells at depths of more than 15,000 ft could eliminate problems with well control, sidetracks and directional drilling. "The Air Force is very interested in finding commercial uses for COIL technology," said Captain Brian G. Quillen, laser systems engineer, Gas/Chemical Laser Technology Branch, Air Force Research Laboratory. "Although developed as a weapon system, a COIL's high power output and inexpensive chemicals make it ideally suited for other applications. One distinct advantage of a COIL that makes it ideal for commercial use is its potential for coupling into fiber optics. This makes it well suited for power projection over long distances, such as oil well drilling." Fig. 2 shows how chemical reactions produce a laser beam.

Two other lasers useful for studying the interactions of lasers and soft rock minerals are:

- **Electric Discharge Coaxial Laser I**—This is another high-powered laser that has been used to investigate the effects of a laser beam on numerous materials in various environments. An extensive database containing 15 years of research has already contributed to a significantly better understanding of the physics of material-laser interaction.
- **Laser Device Demonstration (LDD)**—Both LDD wavelengths (HF and DF) will be useful for determining the interactions of intense laser beams with different soft rock minerals. LDD, a prolific Defense Department research tool, has logged more than 45,000 seconds of laser-materials testing. LDD operational expenses are low enough that the laser rock interaction matrix of a substantial set of rocks and downhole conditions can be developed and explored.

The application of laser technology to drilling has its detractors. The skepticism is based mostly on limited laboratory tests conducted and theories formulated more than 25 years ago, when laser research was in its infancy. At that time, MIT studied lasers with less than a kilowatt of power and large wavelengths that were difficult to focus. Since then, significant advances have been made in laser power generation—megawatts, not kilowatts—efficiencies and transmission capabilities. These advances have yet to be applied to drilling rock.

A promising laser test was recently conducted by Dr. Kenneth Sundberg, senior research scientist at Phillips Petroleum, using the U.S. Army's MIRACL laser to evaluate laser boring applications. The laser beam bored through a sandstone-shale "sandwich" at a penetration rate of 450 ft/hr—more than 100 times current rates. The lased surface was smooth, forming a vitrified sheath that may eliminate the need for concentric casing strings.

Gas Research Institute, based in Chicago, manages a cooperative research, development and demonstration program for the mutual benefit of the natural gas industry and its customers. GRI works with research organizations, manufacturers and its member companies to develop gas technologies and to transfer new products and information to the marketplace. ●

➤CONTRACTS

Conoco And Lukoil Sign Agreement

Lukoil and Conoco have agreed to develop petroleum reserves in the Northern Territories area of Russia's Timan-Pechora Region. More than 1 billion bbl of crude oil and 2 tcf of natural gas are expected to be recovered from the 1.2-million acres, resulting in a possible $25 billion boost on the Russian economy. Lukoil will have 60% interest in the project and Conoco will hold 40%.

YUKSI Signs Teamwork Agreement With Elf

YUKSI and Elf have formed a strategic alliance to develop the Sugmut field, located in Western Siberia, of which 50% interest will be held by both parties. The project has estimated reserves of more than 700 million bbl of oil. According to terms of the deal, Elf will acquire 5% in YUKSI's capital for $528 million.

Petro-Canada Begins Work In Tunisia

Petro-Canada and the Tunisian national oil company, ETAP, have agreed to explore the south central region of Tunisia. The 1.8-million-acre Tataouine block in the Berkine Basin is relatively unexplored and is near several substantial oil discoveries in Algeria.

Conoco, Decisioneering Sign Licensing Agreement

Conoco has included Decisioneering's Crystal Ball risk-analysis and modeling software in its business practices. The deal lets Conoco expand its user-base to include more than 2,000 strategic planners, reservoir analysts and drilling engineers. Crystal Ball is a spreadsheet add-in which allows users to perform risk analysis at all levels, from development to mergers and acquisitions.

Exxon Contracts Global Marine Rigs

Exxon Exploration Co. has awarded Global Marine Inc. a contract for a deepwater drilling rig. Global Marine began construction on a second Glomar 456 Class dynamically positioned drill ship which is estimated to bring in $208 million during a 3-year term. The ultra-deepwater rig is scheduled for delivery in early 2000 and will be outfitted to work in 8,000-ft waters.

Transocean Extends Texaco Contracts

Transocean Offshore received contract extensions from Texaco for two of its second-generation semisubmersibles. The *Transocean 96* contract is for 3 years and the *Transocean 97* contract is for six months. The rigs will be operating in the U.S. Gulf of Mexico and Trinidad and Tobago, respectively.

DGC Hired For Morpeth Field Project

British-Borneo signed Deep Gulf Contractors (DGC) to transport and install four 50-ton completion guide bases and keel haul four 25-ton subsea trees to the drilling rig *Ocean Endeavor* for the Morpeth field development. The work began in March 1998.

Property Divisions Made After McDermott-ETPM Split

The joint venture between J. Ray McDermott S.A. and ETPM has been terminated. J. Ray McDermott received an estimated $105 million in cash and the derrick-lay barge DLB-1601, as well as the minority interest held by ETPM in both the East and Far East regions for McDermott-ETPM. ETPM received the lay barge LB-200, McDermott Subsea Constructors Ltd. (MSCL) and the interest held by J. Ray McDermott in the West region.

Kerr-McGee Bid For Gulf Of Mexico Blocks

Kerr-McGee Oil and Gas Corp. had the highest bid on 19 blocks in the central Gulf of Mexico lease sale No. 169. Kerr-McGee's net total exposure for all high bids was $21.9 million. However, the bids are still awaiting the U.S. Interior Department's Mineral Management Service's approval.

Total Sells To Santa Fe

Santa Fe Energy Resources has signed an agreement to purchase Total S.A.'s interest in the Tuban Production Sharing Contract, which will double Santa Fe's interest in Tuban. Located on the island of Java in Indonesia, the contract area includes several identified exploratory prospects and more than 700,000 acres of exploration acreage. Gross production from the Mudi field exceeds 7,000 b/d of oil and is expected to reach 20,000 b/d by mid-1998. The agreement is subject to approval by the Indonesian government.

Possible Block Addition For EREC

Equitable Resources Energy Co. (EREC) was the highest bidder on 15 of 20 blocks at the Central Gulf of Mexico Federal Lease Sale No. 169. The company bid for 100% working interest on 7 blocks and placed bids with industry partners for 8 other blocks. The bids totaled $15.8 million.

Chevron Signs Exploration Agreement

Chevron signed an agreement with Qatar General Petroleum Corp. (QGPC) to explore for hydrocarbons in the Qatar Peninsula. Chevron will perform 2-D and 3-D seismic surveys on the 10,900-sq-km onshore acreage, which is designated Block 2 and is located east of the Dukhan oil field and south of North Dome gas field.

Occidental Signs Holdings To Union Pacific

Union Pacific Resources Group Inc. will purchase $59 million in properties from Occidental Petroleum Corp. The assets include interests in four oil and gas fields in southwest Wyoming; 23 producing wells in Louisiana; increased ownership in the Masters Creek Gas Plant; and almost 127,000 net acres located in Austin Chalk trend.

Coflexip Stena Wins Phillips Agate Contract

A newly formed joint venture has been awarded a contract for installation services on the Phillips-operated Agate field by CSOI and Cal Dive International. The Agate field is located in Ship Shoal Block 361 in 400-ft waters. Its production will be delivered 6 miles to the Mahogany platform in Ship Shoal 349.

Shell, Vastar Initiate Swap

Vastar Resources and Shell Deepwater Development have announced an agreement to swap interests in several Gulf of Mexico leases. As part of the deal, Vastar will obtain a 25% working interest in the Atwater Valley 136 No. 1 deepwater wildcat well. The agreement involves trading acreage interest in Atwater Valley blocks 134, 135, 136, 137, 178 and 179. The blocks are 145 miles south of New Orleans, La., in 3,500-ft waters. The area is called Paricutin by Vastar and Star by Shell.

➤COMPANY NEWS

Swaco Acquires Mantovani & Vicentini

Swaco, a division of M-I llc, has acquired Mantovani & Vicentini S.R.L. of Berra, Italy. Manotovani & Vicentini operate a fleet of large bowl decanting centrifuges, dewatering, filtration and closed-loop systems, three-phase decanting variable speed centrifuges and mobile purification and solids control companies. The new company will be named Mantovani & Vicentini S.R.L./Swaco MV.

Klaper To Join Oil States Industries

Arlington, Texas-based Oil States Industries and Aberdeen-based Oil States Industries Ltd. (UK), have purchased Klaper Ltd. (UK). The new company name will be Oil States Klaper Ltd. Klaper provides repair and maintenance services for subsea BOP stacks, risers and mud systems in the North Sea.

Tube-Alloy Moves Headquarters To Houston

Tube-Alloy, a division of Grant Prideco, is moving its headquarters from Louisiana to Houston. A 55,000-sq-ft facility is already under construction and completion is expected in the summer of 1998. The new building is located in Northwest Houston at 14333 Sommermeyer. Tube-Alloy's entire product line can be manufactured within this facility, however other manufacturing locations will remain in operation.

tas Adds Processing Capabilities ree Facilities

itas DGC Inc. has added two vlett-Packard V-Class computers to h its Houston and Crawley, UK ı processing centers. The increased ver allows Veritas to process large imes of 3-D data. Veritas DGC has geted $16 million in data process- capital expenditures for the pur- se of additional computer power ts various processing centers for 8.

lmark, GeoGraphix Buy Vantage

liburton Co.'s Landmark Graphics p. and its subsidiary, GeoGraphix , have completed acquisition of tage Software Inc. of Bakersfield, f. Vantage Software provides PC- ed production mapping and surveil- e software.

ision Acquires Northland

cision Drilling Corp. has signed a r of intent to purchase Northland Energy Corp. Northland provides underbalanced drilling systems. The Calgary-based company also provides personnel and surface control equipment for underbalanced drilling programs.

Halliburton Negotiates For Northwest Hutton Property

Houston-based Halliburton Co. is negotiating with Amoco Corp. to buy into an old oil and gas field—the Northwest Hutton property in the North Sea. Amoco has a 25.8% interest in the property. The other partners' approval will be needed and include: Petroleos Brasileiro, Brazil's state oil company (28.46%), Cieco (25.77%), and Mobil Corp. (20%). Authorization of this transaction will allow Halliburton to begin a $100 million to $150 million project to dismantle the platform and plug the field.

OSCA Forms JV With PSL Group

The PSL Group has announced the creation of a joint venture company with OSCA Ocean Technologies Inc. Operational bases for integrated underwater excavation and pipeline services will be located in Houston, New Orleans, La. and LaFayette, La. OSCA will provide pumping services in skid-mounted mobile units or from its fleet of three new-generation, dynamically positioned stimulation vessels.

Wood Group Wins Scotland Engineering Awards

The Wood Group won this year's Scottish Engineering Award. Bill Edgar, chairman and chief executive of the Engineering & Operations Support Division, accepted the award. In addition, a second trophy—the Scottish Engineering/Incorporation of Hammermen Award—was awarded to Michael Wallace of Display Products Technology of East Kilbrid. He won the award for his part in initiating and running a project to repair LCD units.

Petro-Hunt Buys Occidental Properties

Occidental Petroleum Corp. has completed the sale of onshore oil and gas properties in Louisiana and Mississippi to Petro-Hunt llc for about $194 million. Two other Occidental deals closed, including the sale of interest in Wyoming and in the Austin Chalk area of Louisiana to an affiliate of Petroleum Strategies Inc. for about $62 million, and the sale of Oklahoma oil properties to Anadarko Petroleum Corp. for $120 million. Occidental is trying to raise $4.7 billion to fund its common stock repurchase program. The completed transactions, totaling approximately $376 million, are part of a program to divest or redeploy nonstrategic properties.

Expro Group Opens Maintenance Facility In Norway

The oilfield services supplier has opened a purpose-built subsea equipment maintenance facility in Bergen, Norway. The company also confirmed receiving new contracts worth $30 million (£20 million).

Dockwise Successfully Moves Genesis Spar

Dockwise NW moved two sections of the production spar Genesis from Aker Rauma Offshore's construction site in Pori, Finland, to the Aker Gulf Marine Yard in Corpus Christi, Texas, where the sections will be assembled. The two consecutive Atlantic crossings were carried out by the *Transshelf* and lasted 24 days each.

Oceaneering To Expand ROV Fleet

Oceaneering International Inc. announced it will manufacture eight Hydra Millenniums and six Hydra Magnums for delivery by December 1998. The Millennium is a 150-hp work class remotely operated vehicle designed to operate in 10,000-ft or greater water depths and in shallower applications that may require specialized work capability. The Millennium is based on the Magnum series design. ●

D. Baillie

R. Huck

R. Ross

I. Joseph

D. Gauthier

F. Gauthier

M. Fox

P. Ghez

Schlumberger Oilfield Services' has named 3 people as regional presidents of its Solution's group: **David Baillie,** Asia; **René Huck,** Europe and C.I.S.; **Rex Ross,** North America. Several others have been appointed vice presidents and general managers including: **Saad Bargach,** North Africa-Eastern Mediterranean; **Antonio Campo,** Latin America South; **Charles Currie,** West Africa; **Magne Sveen,** Latin America North; and **Adil Toubia,** Middle East Gulf. All the positions will report to **Chad Deaton,** executive vice president of Solutions.

Houston-based ICO Inc. has promoted **Isaac H. Joseph** president of its new oilfield services division, ICO Worldwide.

Brandt has announced the addition of four members to its North American Solids Control Division management team, including **Frank Gauthier,** U.S. sales and marketing manager; **Don Gauthier,** U.S. products and technical development manager; **Mike Fox,** U.S. operations manager; and **Mark Guldry,** remediation division manager.

Philippe Ghez has been selected as the Expro Group's client account manager, responsible for the UKCS/ Norway region.

Stephen C. Pahls has been appointed vice president, sales and marketing for Balmoral Group International Inc. He will now be responsible for all sales and marketing activities for the marine hardware and syntactic foam buoyancy product lines.

Camco Products & Services Co. has appointed **David Black** as executive vice president. In addition to his responsibilities of product sales and wireline services worldwide, he will be involved with Camco Coiled Tubing Services division and Camco's worldwide manufacturing operations.

Robert E. Rose has been named president and CEO of Global Marine Inc. He also has joined the company's board of directors. Rose replaces **John G. Ryan,** who has been on medical leave since February 1998. In addition, Global Marine has promoted several others including: **Jon A. Marshall,** executive vice president and COO; **Marion M. Woolie,** president, Global Marine Drilling Co.; and **Gary L. Kott,** president, Global Marine's international drilling subsidiary.

U.S. Energy Secretary **Federico Pena** has announced his resignation. Pena plans to enter the private sector. No replacement has been named.

William E. Nasser has been elected as Energy Biosystems Corp.'s chairman of the board, CEO and president. Former Chairman of the Board **Ramon Lopez** will remain as a member of the board and the executive committee.

Houston-based Santos USA Corp. has named **Keith E. Jordan** vice president of exploration, production and operations.

The Elf Aquitaine Board of Directors have elected **Jürgen Sarrazin** and **Rober Studer** directors. Sarrazin has served on supervisory boards for Daimler Benz, Krupp, Henkel and Hoechst, as well as the board of directors of the French bank, Banque Nationale de Paris. Studer holds a position as chairman of the board of directors of Union Bank of Switzerland in Zurich, and serves as a member of the board for Nestlé, BASF and Schindler.

AMBAR has added three new members to its management team. **Rick Billings** has been named vice president and general manager; **Russell Freed** has been appointed vice president of marketing; and **David Sullivant** has been named vice president of sales.

James H. Lehmann has been named vice president and general counsel of The M.W. Kellogg Co., the international engineering and construction division of Dresser Industries Inc.

ARCO Latin America has appointed **A.J. "Tony" Best** senior vice president of operations. **Keith I. Weiser,** vice president and regional managing director for ARCO Latin America, will replace Best as president of ARCO Permian.

NOVA Technology Corp. has elected three members to its board of directors, including **Alan A. Baker, Ernest L. "Chick" Williamson,** and **Crichton W. Brown.** Baker retired as chairman of Halliburton Energy Services in 1995 after 41 years with the company. Williamson previously served as chairman and CEO of Louisiana Land & Exploration (LL&E). Brown is currently with Advantage Capital Corp. as a principal and managing director.

ı Measurement Software

ıamic Engineering Solutions ırvada, Colo., has released ısZ for Windows, a compre- sive software program that :ulates natural gas flow ıugh a flanged tapped orifice er per the latest API 14.3 A 3). Gas density and com- ssibility factors are calculat- ver the latest API 1.2 (AGA 8). program provides 35 solu- parameters and five flags, :autions. Purchasers can ose from the single user nse or the multiple user ıse that includes the Visual ic source code.

Circle 150

hore Engineering

: Inc. of Houston, has a new chure that details its off- e engineering and construc-

ı services. The company ides a mix of technical and ds-on expertise for offshore elopment companies. OPE ides project management structural engineering ser- s, turnkey projects, pipeline ineering offshore and ıore and piping engineering. company also provides civil material engineering, weld- and mechanical engineer- as well as computer aided ting in 2-D and 3-D.

Circle 151

rable Turbodrill

rfor-Weir of Glasgow, land, has introduced its lat- addition to its line of anced capability steerable odrills, a 9¼-in. tool. Based proven FBS technology ady available in smaller sizes, the development oves reliability and perfor- ıce to directional drilling operations in 12¼-in. hole sections. The 9½-in. FBS features power delivery up to 900 hp; speed responsive blade pressure; high temperature capability to 220°C; and balanced drum thrust reduction.

Circle 152

Centrifugal Compressors

Dresser-Rand Turbo Products Division's DATUM centrifugal compressors have introduced a modular design that reduces service costs and downtime. Higher efficiencies have translated into increased capacities in same-sized units. DATUM centrifugal compressors are used for refrigeration and syngas in ammonia production; charged gas and propylene refrigeration for ethylene production; syngas for methanol; wet gas service in refining; gas lift and reinjection for oil production; and gas storage in natural gas production.

Circle 153

Data Processing

Geco-Prakla is using Sun Microsystems Ultra Enterprise "Starfire" server at its processing centers in Gatwick, England, and Houston to enhance data processing capacity. The new server provides a significant improvement to Geco-Prakla's turnaround capabilities and supplies an efficient engine for prestack migration and similar intensive processes under development. The server's architecture complements the volume-throughput, multi-node and parallel-processing design of Geco-Prakla's SEIS-MOS integrated processing system.

Circle 155

Thread Compounds

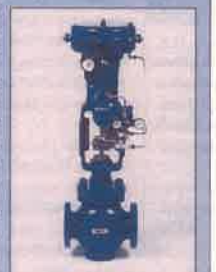
Houston-based **Galaxie International's** catalog features an environmentally safe tool joint compound. Introduced in the

catalog is the metallics-free tool joint compound Premium Enviro-TJ. The catalog also describes in detail 19 thread compounds for use on tool joints and rotary connections. Also included are other Galaxie products made for oil and gas exploration and production that are available worldwide including cleaners and degreasers, anti-seize and specialized lubricants for equipment operations, marine and jackup lubricants, wireline lubricants and protective coatings.

Circle 156

Control Valves

Norriseal of Houston, has combined the features of its field-proven Series 2700 and 2703 control valves into the new Series 2700A and Series 2800E, resulting in a versatile high performance control valve for a wide range of pressures and temperatures with several material and trim options. The family of valves offers the flexibility to select the exact valve for a specific application. The single-ported valve bodies have balanced, unbalanced and restricted port trims that offer a wide range of flow characteristics. Unique design features include cage characterized noise abatement, anti-cavitation trims, fugitive emission seals, No. 12, 16 or 18 yoke mounted diaphragm actuators and direct or reverse acting pneumatic actuators.



Circle 154

Reamer Shoe

Weatherford Enterra Inc. has become the exclusive supplier and global distributor for the Brit Bit Ltd. (BBL) reamer shoe product line. The BBL reamer shoe is a bullet-shaped tool used in casing installations to overcome formation difficulties such as tight clearances that prevent the passage of conventional casing shoes into the well bore. BBL reamer shoes use polycrystalline diamond cutting elements or tungsten carbide hard-faced blades. The shoes have particular application in horizontal high torsion pipe or top drive wells.

Circle 157

Oilfield Tools

TIW Corp. has a 68-page catalog featuring its line of liner equipment, packer systems,

and kelly and safety valves for the oil and gas industry. The catalog provides descriptive information and specifications on the entire line of liner hanger, packer and completion tool products offered by TIW. Detailed product illustrations are also included in the catalog.

Circle 158

Hole Openers

Stabil Drill offers a full line of hole openers, including custom-built large-diameter hole openers. For drilling, Stabil Drill offers three basic types of hole openers: the Integral Body, the Collector Box style and the DrillRite™. The Integral Body includes 2-4 cutters; the Collector Box style allows fluid flow to be evenly distributed directly onto cutters for improved cleaning action; and the DrillRite provides excellent cutting action in all formations.

Circle 159

DATE	EVENT	INFO-PHONE
1998		
June 9-11	National Petroleum Show, Calgary, Alberta, Canada	
June 14-18	API Production Annual Standardization Conference, Hyatt Regency Reunion, Dallas, Texas	202-682-8149
June 14-18	Air & Waste Management Association's 91st Annual Meeting and Exhibition, San Diego Convention Center, San Diego, Calif.	412-232-3444
June 15-20	Society of Women Engineers Annual National Convention and Student Conference, Hyatt Regency, Houston	281-874-8848
June 16-17	OCS Safety and Legislation Compliance for FPSO Training Course, Kippie Lodge, Aberdeen	44-1224-695-684
June 22-26	NEFTEGAZ '98—7th International Trade Fair for Equipment, Krasnaya Presnya Fairgrounds, Moscow, Russia	312-781-5180
June 24-27	Oil & Gas Technology Philippines '98, Manila	44-0171-862-2073
June 29-30	Coiled Tubing, The Doubletree at Allen Center, Houston	508-481-6400
June 29-Jul. 3	University of Michigan Center for Professional Development Short Course on Fluid Transient Analysis, Ann Arbor, Mich.	313-647-7200
July 5-10	SPE Forum Series in North America—Dynamic Reservoir and Production Optimization Using Intelligent Wells, Breckenridge, Colo.	972-952-9393
July 8-10	SPE/ISRM Eurock '98, Trondheim, Norway	44-171-487-4250
July 12-17	SPE Forum Series in North America—Impact of Pore-Scale to Well-Test Scale Data Relationships, Breckenridge, Colo.	972-952-9393
Aug. 3-7	SAH Advanced Production Enhancement Using Nodal Analysis, Hilton West, Houston	281-558-9120
Aug. 20-21	AUV '98—Autonomous Underwater Vehicles, Cambridge, Mass.	617-258-3097
Aug. 24-26	10th International Conference On Horizontal Well Technologies, Houston	214-841-0044
Sept. 1-3	OCS Petroleum Economics, Selfridges Hotel, London	0171-408-2080
Sept. 7-9	IADC/SPE Southeast Asia Drilling Conference, Jakarta Hilton	281-578-7171
Sept. 13-18	17th World Energy Council Congress, Houston	
Sept. 13-18	SEG 1998 International Exposition and 68th Annual Meeting, New Orleans, La.	918-497-5500
Sept. 14-16	2nd Middle East Refining and Petrochemicals Conference and Exhibition—PetroTech '98, Manama, Bahrain	713-668-1007

FREE computerized analysis aids pumping of deviated wells

A computerized analysis service is now available to the operators of deviated pumping wells. It is designed to help reduce rod and tubing wear and increase pumping efficiency.

Operators are asked to provide a directional survey and answers to 12 questions: pump size and depth, stroke length, strokes per minute, etc.

The analysis shows the rod load-weight plus drag or friction — by well depth increments. If the rod string is under-designed, the analysis may suggest changes in rod sizes and types. Also it may make recommendations for the centralization of the rod string at strategic well points — including the use of scrapers, molded-on and/or clamp-on rod guides, and Wheeled Rod Guide Couplings.

(SUBJECT TO TIME PERMITTING)

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ADVERTISER AND COMPANY INDEX

CLASSIFIEDS

Hart's Petroleum Engineer® INTERNATIONAL

June 1998

La Revista de Tecnología de Perforación y Producción Mundial: Terrestre y Marina

BRAZIL

The Sleeping Giant Stirs

Brazil's oil and gas industry is fast opening up to international oil and gas companies. But a few things still need to be worked out.

Se Despierta el Gigante

La industria petrolera brasileña está abriendo rápidamente las puertas a las empresas internacionales. Pero aún faltan por revolverse varios asuntos.

For years, Brazil has been called the sleeping giant—and with good reason. The country spans an area bigger than the 48 contiguous United States. Its population of 164 million is larger than Russia's. And its gross domestic product amounts to a whopping $880 billion.

But the sleeping giant has started to stir. For the last 10 years, exploration and production of Brazil's oil fields has been reserved to state-owned oil company Petroleo Brasileiro S.A. (Petrobras), the 15th largest oil company in the world. In 1995, however, Brazil passed a constitutional amendment that did away with Petrobras' oil monopoly. While it retains first rights to any existing wells, foreign companies are allowed to explore new fields, either on their own or with Petrobras as a joint venture partner.

Recently, the company created the Consulting Office for New Deals and Partnerships (ANEP) to expand its operations internationally as well as to choose projects and partnerships in Brazil itself. It also created a new government entity, the Agencia Nacional de Petroleo (ANP), to regulate the industry and dole out conces-

Por muchos años se ha dicho, con mucha razón, que el Brasil es un gigante dormido. Su territorio es más grande que el de los 48 estados contiguos de los EE.UU. y su población, de 164 millones, es más alta que la de Rusia. Más aún, su producto bruto nacional asciende a la astronómica suma de US$800.000 MM.

Ahora, el gigante ha empezado a despertarse. Desde hace 10 años, las empresas extranjeras no tenían acceso a operaciones brasileñas de exploración y producción, tareas sobre las cuales la empresa petrolera estatal Petrobrás (la decimaquinta más grande del mundo) ejercía total monopolio. En 1995, empero, el Brasil enmendó su constitución y abolió el monopolio. El país retiene derecho prioritario sobre los campos existentes pero a las empresas privadas se les permite explorar en busca de nuevas reservas, ya sea por su propia cuenta o en sociedad con Petrobrás.

Recientemente, Petrobrás creó una nueva entidad, la Oficina de Consultas de Nuevos Pactos y Sociedades (ANEP) para ampliar sus operaciones internacionales y escoger proyectos y socias para operaciones en el Brasil. Creó también la Agencia Nacional del Petróleo (ANP), una

by **Claire Poole**
por **Claire Pool**

sions and contracts to outside companies.

Now there's even talk of privatizating Petrobras. The law says that the government will keep 50% of Petrobras plus one share. Analysts think Petrobras will eventually privatize by selling off more of its stock, much like YPF of Argentina did several years ago. The move would bring more capital into the company and take Petrobras' expenses, which are considerable, off the federal budget.

Despite its reluctance to give up its cherished black gold, clearly Brazil has to do something. Apparently, it can: the country has significant oil and gas reserves. According to Gustavson Associates, a Boulder, Colo. consulting firm that published an extensive study on Brazil in 1996, the country's estimated undiscovered recoverable resources exceed 16.2 billion bbl of oil equivalent. But despite some 7,200 productive wells now operating, reserves still lie largely untapped under rain forests and in deep waters offshore.

Demand Vs. Production

With domestic oil consumption growing about 6% per year (to 1.7 million b/d in 1997), Brazil is a net importer of crude oil and related products. Last year, daily production averaged 869,000 bbl. But, it reached the crucial 1-million-bbl mark on Dec. 17—a figure also forecast to be the average daily output during 1998. Despite this achievement, Brazil consumed 1.4 million bbl during the past year, meaning it imported about 576,000 b/d just to keep up with demand. The cost? More than $3.8 billion. Petrobras estimates that oil imports will cost $6 billion this year, accounting for about half of the country's trade deficit.

nueva entidad estatal que regulará la industria y otorgará concesiones y contratos a empresas petroleras privadas.

Ahora, incluso, se habla de privatizar a Petrobrás. La ley dice que el gobierno mantendrá el 50% más una de las acciones de Petrobrás. Muchos analistas creen que a la larga Petrobrás se privatizará vendiendo más y más de sus acciones, tal como ocurrió hace algunos años con YPF de Argentina. Si tal cosa ocurriera, la empresa recibiría una infusión de capital y sus elevados gastos no correrían saldrían del presupuesto federal.

A pesar de su aversión por renunciar su codiciado oro negro, el Brasil tenía que hacer algo. Aparentemente puede hacerlo, ya que posee abundantes reservas de petróleo y gas. Según informa Gustavson Associates de Boulder, Colorado, E.U.A., firma consultora que publicó en 1996 un extenso estudio del Brasil, las reservas pendientes de descubrirse son de más de 16.200 MM bls equivalentes en petróleo. Pero, a pesar de los 7.200 pozos actualmente activos, gran parte de las reservas potenciales están en la selva y en aguas profundas del Océano Atlántico.

Consumo vs. Producción

En el Brasil, la demanda aumenta 6% anualmente (la de 1997 fue de 1.700.000 b/d) y para satisfacerla debe importar petróleo crudo y productos refinados. El año pasado, la producción local promedió 869.000 b/d y el 17 de diciembre llegó a 1.000.000 b/d, volumen que Petrobrás espera mantener en 1998. Las importaciones montaron 576.000 b/d, a un costo de US$3.800 MM. Petrobrás calcula que este año el costo de las importaciones será de US$6.000 MM, o sea la mitad del déficit de la balanza comercial del Brasil.

Apremiado por el notable aumento de la demanda, el gobierno quiere cambiar la situación y espera producir 1.200.000 b/d este año, 1.300.000 b/d. en 1999 y 1.500.000 b/d en el año 2000. De lograrse esas metas, las importaciones bajarían de 48% a 25%, según calcula Hugo Napoleao, senador del Partido Frente Liberal, coautor de la nueva legislación petrolera.

Si los aumentos continúan, el Brasil podría alcanzar su autosuficiencia—esperanza ésta que el gobierno abandonó hace varios años. "Pronosticamos que el drástico aumento de las reservas de petróleo le dará al Brasil su autarquía energética en 1999 y lo convertirá en exportador en 2000," dijo en el informe de enero de 1998 de la firma Salomon Smith Barney su analista de recursos naturales Robert Goldman.

Aunque Petrobrás afirma que descubre 4 bls de petróleo por cada uno que produce, lo cierto es que el Brasil necesita ayuda. Aunque la empresa ha venido invirtiendo US$700 MM anualmente en exploración, en abril tuvo que negociar un empréstito de US$1.150 MM con el Banco de Desarrollo Nacional para continuar el desarrollo del

Faced with spiraling demand, the government wants to change this picture. Its aim is to produce 1.2 million b/d this year, 1.3 million next year and 1.5 million by 2000. If those goals are met, the national dependence on oil imports will drop from 48% to 25%, according to Hugo Napoleao, a federal senator from the Liberal Front Party who helped write some of the new legislation.

If it continues at that rate, Brazil could eventually become self-sufficient—a hope it abandoned several years ago. "We project that dramatic increases in oil reserves will make Brazil self-sufficient with respect to oil by 1999 and a net exporter by 2000," Robert Goldman, a natural resources analyst at Salomon Smith Barney, wrote in a January 1998 report.

Even though Petrobras says it finds 4 bbl for every one produced, Brazil cannot go it alone. Recently, it has been able to invest only $700 million in exploration annually, however, in April, the company borrowed $1.15 billion from Brazil's National Development Bank (BNDES) to boost its output at the Marlim field in the Campos Basin. That's a drop in the bucket compared to what it needs to bring its oil to the surface.

Strong Competition

Too, its oil-rich neighbors—Argentina, Venezuela, Ecuador, Colombia and Peru—have attracted billions of dollars in foreign investment. So, government officials have hit the road, seeking joint venture partners. In April, at a Houston conference sponsored by the InterAmerican Chamber of Commerce, Peter Greiner, Brazil's otherwise gruff Undersecretary of Energy, extended an open invitation: "We are facing a historic moment in energy," he said. "Come be a partner of Brazil."

The international majors are more than eager, sending representatives, opening offices and trying to navigate the federal bureaucracy. "The opportunities in Brazil are staggering," Bruce Appelbaum, president of Texaco Exploration, said at the Houston conference. "We will all see the benefits of this opening."

Petrobras itself is seeking investment in 100 different projects at a total investment of $110 billion. The first round of competitive bidding isn't expected until the second half of this year, but so far, private companies or groups have presented proposals for joint ventures in 62 different E&P projects, 44 for exploration.

The company has whittled the list down to 42 projects. It has already signed 19 preliminary joint venture agreements; another 13 are in the process of being signed.

According to Washington, D.C.-based newsletter "Latin American Energy Alert," Texaco, in a consortium with Exxon, Shell and Japan's Mitsubishi, has won the right to develop the deepwater Albacora Leste field in the Campos Basin. Texaco spokesman Paul Weediz wouldn't comment, but Appelbaum noted in his speech that the company is busy preparing for pos-

campo Marlim en la Cuenca de Campos. Y esa no es sino una mínima parte de los fondos que requiere el Brasil para extraer su petróleo.

Fuerte Competencia

Por otra parte, los vecinos del Brasil—Argentina, Venezuela, Ecuador, Colombia y Perú—ricos en petróleo, han podido atraer miles de millones de dólares de inversiones extranjeras. Por eso, funcionarios del gobierno brasileño han empezado a viajar en busca de socios. En abril, durante una conferencia patrocinada por la Cámara Interamericana de Comercio, Peter Greiner, Subsecretario de Energía del Brasil, extendió una franca invitación: "Estamos frente a un momento histórico," dijo "vengan al Brasil y háganse socios."

Las empresas petroleras internacionales están ansiosas; envían representantes, abren oficinas y tratan de navegar el mar de la burocracia federal. "Las oportunidades del Brasil son monumentales," dijo durante la conferencia de Houston Bruce Appelbaum, presidente de Texaco Exploration. "Todos vemos los beneficios de esta apertura."

Por su parte, Petrobrás busca capital para 100 proyectos diferentes que costarán US$100,000 millones. Aunque la primera ronda de licitaciones no se espera sino durante el segundo semestre de este año, varias empresas privadas, individualmente o en grupos, ya han hecho propuestas para operaciones conjuntas con Petrobrás para más de 100 proyectos: 62 de E&P y 44 de exploración.

La lista se ha reducido a 42 posibles pactos de asociación. De estos, 19 ya han recibido aprobación preliminar y 13 están a punto de firmarse.

Según informa "Latin American Energy Alert," carta de noticias que se publica en Washington, D.C., a un consorcio formado por Exxon, Shell y Mitsubishi (Japón) se le ha otorgado el derecho de desarrollar el campo Albacora Este, de aguas profundas, situado en la Cuenca de Campos.

Los pactos más atractivos son los de exploración y producción, incluso los de Pescada-Arabaiana/1-RNS-128, en la Cuenca de Potiguar; 1-BAS-097, en la Cuenca de Camamu; 1-SES-107D, en la Cuenca de Sergipe; y 1-RJS-366 en la Cuenca de Campos.

Los proyectos de desarrollo del campo Albacora Este y 1-SES-107D, este último en la Cuenca de Sergipe, han despertado notable atención. Y a las empresas privadas les intriga les intriga el potencial de operaciones de recuperación mejorada en el campo costafuera de Cacao y los terrestres de Fazenda Cedro Norte, Fazenda Queimados y Río Itaunas, todos situados en la Cuenca de Espíritu Santo, así como otros campos de las cuencas de Recôncavo y Sergipe-Alagoas.

Antes de que se ejecute cualquiera de esos proyectos será necesario determinar las condiciones fiscales, de las cuales la más importante es la estructura de los impuestos sobre la renta. Los impuesto federales son de 25% y los estatales, para la industria petrolera, fluctúan entre 12% y 37%. Para empezar, pues, la tajada de impuestos podría ser de 55%, incluidas las regalías de 5% o de 10%, según sea la

sible operation in the Campos Basin and has already hired 150 people.

The most popular deals? Combination exploration/production projects, including Pescada-Arabaiana/1-RNS-128 in the Potiguar Basin, 1-BAS-097 in the Camamu Basin, 1-SES-107D in the Sergipe Basin and 1-RJS-366 in the Campos Basin.

Development projects in the Albacora Leste field and the 1-SES-107D oil discovery in the Sergipe Basin have attracted keen interest. Companies also are intrigued by enhanced oil recovery projects, including the offshore Cacao oil field and the onshore Fazenda Cedro Norte, Fazenda Qucimados and Rio Itaunas oil fields, all in the Espirito Santo Basin, as well as fields in the Reconcavo and Sergipe-Alagoas Basins.

Before any of these projects can move forward, the fiscal terms still need to be worked out. The most important is the tax structure. Federal income taxes are 25% and state taxes for the oil and gas industry range from 12% to 37%. The up-front tax bite could reach as high as 55%, which includes royalties of between 5% and 10%, depending on the bid. "That would be an excessive burden," Texaco's Appelbaum said at the conference. Rex Gaisford, executive vice president of worldwide development at New York-based Amerada Hess, agreed: "These front-end taxes would be unsustainable for large investments."

Dollars Or Local Currency?

Another important consideration is the use of foreign currency. Under current law, all bookkeeping, transactions and deposits at local banks must be in Brazilian real. Foreign oil companies are asking for the flexibility to use different currencies to obtain financing, buy equipment and export crude. This would avoid devaluation risks as well as transaction and administrative costs. "Other countries around the world do this," David I. McEvoy, vice president of business development at Exxon Exploration Co., told the conference attendees. "We seek the same from Brazil."

The Brazilian government has so far resisted it. The other option is indexing, which would allow foreign oil companies to have their compensation or income pegged to the dollar, which wouldn't reduce the transaction and administrative costs but would eliminate the foreign exchange risk.

All the fiscal terms are expected to be set forth by presidential decree in a few months. Foreign oil companies, which have expressed their concerns to the government, are waiting with baited breath.

In the end, the ANP will control all the strings, and companies are anxious that it operate in an efficient, transparent way. "The ANP has a unique opportunity to create an environment favorable for international investment," Thomas Melsen, vice president of the Americas/Far East for Amoco's exploration group, said at the Brazil conference. "Will they set up invitations or barriers to entry?"

In the meantime, government officials are urging

naturaleza de la oferta. "Esa carga tributaria sería excesiva," dijo Appalbaum de Texaco en la conferencia de Houston. Y Rex Gaisford, vicepresidente de desarrollo mundial de Amerada Hess, concordó al afirmar que "ese régimen impositivo no sería sensato para inversiones grandes."

¿Dólares o moneda local?

Otro factor de importancia es el uso de moneda extranjera. Bajo la ley vigente, toda la contabilidad, las transacciones y los depósitos en los bancos locales deben hacerse en moneda brasileña (el real). Las empresas extranjeras piden flexibilidad para usar diferentes monedas en la obtención de financiamientos, compras de equipos y exportación de petróleo. Tal medida las ampararía contra el riesgo de devaluaciones y mantendría estable su costo administrativo y el de sus transacciones. "En otros países del mundo eso es posible," le dijo a los asistentes de la conferencia David I. McEvoy, vicepresidente de desarrollo comercial de Exxon Exploration Co. "en el Brasil esperamos lo mismo."

Hasta ahora, el gobierno brasileño se ha mostrado reacio. La otra opción es un sistema de índice, el cual le permitiría a las empresas extranjeras equiparar su compensación y/o sus ingresos con dólares de los EE.UU. Tal enfoque no disminuiría los costos administrativos ni de transacciones, pero eliminaría el riesgo de devaluaciones de la moneda local.

Al final de cuentas, la ANP moverá todas las cuerdas y las empresas esperan ansiosamente que la nueva entidad funcione eficiente y abiertamente. "La ANP tiene la singular oportunidad de creár un ambiente propicio para las inversiones internacionales," dijo Thomas Melsen, vicepresidente del grupo de exploración de Amoco para las Américas y el Lejano Oriente. "Para entrar en Brasil, ¿hará francas invitaciones o pondrá obstáculos?"

Al mismo tiempo, funcionarios del gobierno le urgen a las empresas extranjeras que se asocien con Petrobrás. "Si se unen a un monopolio corren menos riesgo," dijo en Houston Greiner, Subsecretario de Energía.

Quiénes Están Interesados

Para empezar, una empresa (ARCO, radicada en Los Angeles) ya ha saltado a la palestra. ARCO no es una recién llegada al Brasil, ya que sus relaciones con ese país datan de la década de 1920, a través de Atlantic Refining Co. A principios de los años 1990. ARCO tenía 1.600 empleados y ventas anuales de unos $1.800 MM/año, ocupando así el noveno lugar entre las empresas privadas más grandes del país.

Sin embargo, en 1993 ARCO vendió sus bienes y operaciones del Brasil a la empresa local Companhia Brasileira de Petróleo Ipiranga. "Esa decisión de ARCO-Brasil fue puramente estratégica," afirmó entonces William C. Rusnack, presidente de ARCO Products Co. "Nuestras actividades brasileñas no eran parte de nuestro núcleo comercial completamente integrado."

ARCO ha cambiado su actitud. En febrero abrió oficinas en Río de Janeiro y ha firmado dos pactos preliminares para operaciones conjuntas con Petrobrás, aunque

'eign companies to pair up with Petrobras. "If you n with a monopoly, there's less risk," Undersecretary einer said in Houston.

ho Wants To Get Involved

s Angeles-based Atlantic Richfield (Arco), for one, is nping in. Not exactly a newcomer to the country, its rliest experiences date back to the 1920s with antic Refining Co. In the early 1990s, the company

no ha indicado la naturaleza de ellos. "Estamos evaluando muchas cosas," declara Albert Greenstain, gerente de relaciones públicas de ARCO.

Exxon ha estado en Brasil desde 1912. La empresa no revela si tiene pactos pendientes con Petrobrás, pero su interés es innegable. "Brasil ha logrado mucho en los últimos años," dijo McEvoy en la conferencia de Houston. "Esperamos poder trabajar con este socio."

Hace 1 año, Amerada Hess abrió oficinas y no oculta su ansiedad por iniciar actividades. La empresa no revele qué busca. "Estamos muy, muy interesados," dijo Carl Tursi, vocero de la empresa, "Hay muchos prospectos potenciales en aguas profundas, y en ese renglón tenemos experiencia. Tenemos disponible un equipo de perforación marina y estamos, pues, listos para entrar en acción si nos escogen."

El año pasado, Amoco hizo una oferta para comprar Cegas, una red de distribución de gas cercana a Río de Janeiro, pero Enron fue la ganadora de la licitación. Neil Chapman, representante de Amoco, dice que su empresa busca también oportunidades para explorar.

Chevron, empresa radicada en San Francisco, ha abierto un compás de espera. Desde hace muchos años, Chevron vende en el Brasil combustibles y lubricantes, y le proporciona soluciones tecnológicas a Petrobrás. En las décadas de los años 1970 y 1980 trató en vano de conseguir contratos de riesgo en las rondas que ofreció Petrobrás. Cuando el gobierno anunció que estaba abriendo las puertas de la industria petrolera a empresas privadas, Chevron instaló oficinas en Río de Janeiro.

"Tan pronto como se hicieron los anuncios más recientes, indicando que todo el sector de la energía se abriría para las empresas privadas, decidimos que tendríamos una buena oportunidad para explorar," dijo Raffaella Cristanetto, gerente de asuntos externos de Chevron Latin America, con sede en Caracas.

Las empresas europeas también esperan firmar pactos; entre otras, Statoil y Norsk Hydro de Noruega; British Gas y Enterprise Oil del Reino Unidos; Elf Aquitaine y Total de Francia; y Repsol de España. YPF de Argentina y Japex del Japón también están husmeando.

Más aún, no faltan las empresas

owned ArcoBrasil Partipacoes e Investimentos Ltda., which had 1,600 employees and annual sales of around $1.8 billion, making it the ninth-largest private company in Brazil.

But in 1993, Arco sold out to Brazilian oil concern Companhia Brasileira de Petroleo Ipiranga. "The decision to sell ArcoBrasil was strictly strategic," William C. Rusnack, president of Arco Products Co., said at the time. "The Brazilian activities are not part of our integrated core businesses."

Arco has changed its tune: In February it opened an office in Rio de Janeiro and it has signed two pre-joint venture bidding agreements with Petrobras. But it won't specify which projects it's looking at. "We're evaluating a lot of things," said Albert Greenstein, Arco's manager of media relations.

Exxon is also there, having had an office in Brazil since 1912. The company won't comment on whether it has any pending deals with Petrobras. But its interest is clear. "Brazil has accomplished much in the last few years," McEvoy said at the Houston conference. "We look forward to working with such a partner."

Amerada Hess opened an office a year ago and is anxious to get going. The company won't comment on what deals it may be pursuing, "but we're very, very interested," Spokesman Carl Tursi said. "There's a lot of potential and deepwater prospects, which we have some expertise in. And we already have a rig available. So we're prepared to go if we're the one they choose."

Royal Dutch/Shell is interested in building and buying natural gas networks. (It already owns 20% of a Sao Paulo network.)

Last year, Amoco bid on Cegas, a local distribution network near Sao Paulo. But Enron ended up winning the bid. Amoco spokesman Neil Chapman said the company is also looking at exploration opportunities from a small office it opened in Rio.

San Francisco, Calif.-based Chevron is taking more of a wait-and-see attitude. The company has been selling fuels, lubricants and technological solutions to Petrobras for years. It even pursued some of the risk service contracts Petrobras offered in the late 1970s and early 1980s, but with little success. When the government announced it was opening up the country's energy sector, Chevron opened an office in Rio de Janeiro last December.

"Once the more recent announcements were made by Brazil that the energy sector overall would be opened, we decided that this would be a good opportunity to explore," said Raffaella Cristanetti, manager of external affairs for Chevron Latin America in Caracas.

Bakersfield, Calif.-based Occidental Petroleum, however, has reportedly pulled out of negotiations with Petrobras, citing lack of transparency in the partnership process. An Occidental Petroleum spokesman didn't return calls seeking comment.

European companies are also scouting for deals, including Statoil and Norsk Hydro from Norway; British Gas and Enterprise Oil from the U.K.; Elf

uitaine and Total from France; and Repsol from ain. Japex from Japan and YPF from Argentina are o sniffing around.

Even the smaller E&P companies are interested, :luding Vintage Petroleum, Kerr-McGee, Unocal, illips Petroleum and Benton Oil and Gas. Houston-sed Pennzoil has signed a pre-joint venture agree-:nt with Petrobras, but Bill Davis, senior vice presi-:nt and general manager of international exploration d production, is waiting to see what the rules look e before he signs on the dotted line. "The fiscal ms have to cover the risk involved," he said.

Houston-based Union Texas Petroleum hasn't yet :ned a preliminary deal with Petrobras. But it has :cussed several possible joint venture deals. "Brazil a country of long-term interest to us," said John P. ein, UTP's director of business development for the nericas. "If the fiscal terms won't allow our company make sufficient economic returns on our invest-:nt, that would be a stumbling block. In today's rld, there's a lot of competition for investment dol-s. They'll have to offer terms that are going to work."

Whatever happens, Brazil is well on its way to open-g up its oil and gas sector to private interests. "Brazil ll never be the same again," Amerada Hess' Gaisford d at the conference. "There is no turning back." ●

pequeñas y medianas que también muestran interés, incluso Vintage Petroleum Kerr-McGee, Unocal, Phillips Petroleum y Benton Oil and Gas. Pennzoil, empresa radicada en Houston, ha acordado un pacto preliminar de asociación con Petrobrás; pero Bill Davis, vicepresidente y gerente general de operaciones internacionales de E&P, dice que, antes de firmarlo, su empresa esperará hasta que se conozcan todas las reglas. "Las condiciones fiscales deben tener en cuenta los riesgos consiguientes," dice Davis.

Union Texas Petroleum, con sede en Houston, no ha firmado pactos preliminares con Petrobrás pero ha discutido varias posibilidades de asociación. "Brasil nos interesa a largo plazo," afirma John P. Klein, director de desarrollo comercial en las Américas. "Si las condiciones fiscales no le permiten a nuestra empresa obtener utilidades razonables sobre nuestras inversiones, eso sería un serio obstáculo. En el mundo actual hay mucha competencia para obtener inversiones en dólares. El Brasil tendrá que ofrecer incentivos para atraer capital extranjero."

Pase lo que pase, el Brasil ha recorrido ya un largo trecho para abrirle a las empresas privadas las puertas de su industria petrolera. "Brasil nunca volverá a ser como era antes," dijo en la conferencia de Houston Gaisfor de Amerada Hess. "Ya no puede echar un paso atrás." ●

OPEC's Role Discussed

Discute Papel de OPEC

While overproduction by member countries is blamed by the current weakening of oil prices, Venezuela's impact is minimal.

Aunque a la sobreproducción de los países miembros se achaca el debilitamiento de los precios del petróleo, el impacto de Venezuela es mínimo.

A 200,000 b/d-production cutback could be viewed as a "drop in a bucket" in a world currently awash in oil, but for Venezuela it represents a significant blow. Last April, in compliance with the agreement of OPEC and non-OPEC countries, Venezuela officially announced such a cut, thus reducing its output from 3.37-million b/d to 3.17-million b/d. Venezuela's OPEP production quota is 2.58-million b/d.

In a recent essay, the President of Petróleos de Venezuela S.A. (PDVSA), Dr. Luis Giusti, expressed his concern about the current world market situation and defended Venezuela's overproduction as an unavoidable means of economic survival.

Within the OPEP member countries, Giusti asserted, Venezuela's situation is unique because of the nature of its oil resources. Of the 74 billion bbl of the country's total proved oil reserves, he explains, "58% correspond to heavy and extra-heavy oil; and those of the fabled Oil Belt of the Orinoco fall in the latter category. Therefore, the majority of Venezuela's crudes have no direct access to the international markets—simply because they can't be refined by conventional processes, which are the most prevalent in the world's refining industry."

To illustrate Venezuela's plight, Giusti explained that a conventional refinery processing West Texas Intermediate crude can expect a high yield of light products and only 25% of low-cost heavy residual oil. If the same refinery were to process extra-heavy crude, he said,

Si una baja de producción de 200.000 b/d podría tildarse como una gota de agua en el mar, en un mundo ahora se ahoga en petróleo, para Venezuela representa un serio golpe. En abril, para cumplir con el acuerdo pactado entre países miembros y no miembros de OPEP, Venezuela anunció oficialmente tal reducción, disminuyendo así su producción diaria de 3,37 MMbls a 3,17 MMbls. La cuota de producción de Venezuela, fijada por OPEP, es de 2,58 MMbls.

En un ensayo recientemente, el Dr. Luis Giusti, Presidente de Petróleos de Venezuela SA. (PDVSA), expresó su preocupación por la situación actual del mercado petrolero mundial y defendió la sobreproducción de Venezuela como un inevitable medio que requiere el país para sobrevivir económicamente.

Entre los países miembros de OPEC, afirma Giusti, la situación de Venezuela es singular a causa de la naturaleza de sus reservas de petróleo. De los 74.000 MMbls de reservas probadas venezolanas, explica, "el 58% corresponde a crudos pesados y extrapesados; adicionalmente, todos los crudos de la Faja del Orinoco pertenecen a esa misma categoría. En consecuencia, la mayoría de los petróleos venezolanos no tiene acceso directo a los mercados internacionales porque no son fungibles; o sea, que no pueden consumirlos los sistemas convencionales de refinación, que constituyen el grueso del parque refinador del mundo.

Para ilustrar el problema venezolano, Giusti explica que una refinería corriente, al procesar Crudo Intermedio

by **Alvaro Franco**, Contributing Editor

it would yield 75% of residue—a volume that would turn the operation into an economic disaster.

"Because our heavy oil has no direct access to the world markets," he continued, "we had to develop a long-range market penetration program that requires substantial investments in the so-called deep conversion processes to transform it into saleable products. To achieve this objective, 4 to 6 years are needed. This explains why Venezuela can't adopt as a sound marketing policy increasing and decreasing its oil output (as dictated by world demand). This can only be done by countries that produce conventional oil, such as those of the North Sea region, Saudi Arabia, Kuwait and other nations of the Middle East."

OPEC's Role

Analyzing the role of OPEC since its inception in 1960, Giusti affirmed that during its first decade the organization achieved modest results within its primary goal of achieving "just" oil prices for its members. "During the 70s," he recalled, "a series of political upheavals in the Middle East (the unilateral Libyan embargo in 1970, the Yom Kipur was in 1973, the Iranian revolution in 1979 and the beginning or the Iraq-Iran war), skyrocketed oil prices and economically rewarded the exporting countries beyond their most optimistic expectations."

The substantial price increase, however, worked against producing countries because the importing nations carried out successful campaigns to save energy and to substitute oil products by other energy sources. Furthermore, affirmed Giusti, high oil prices fostered the development of substantial volumes of reserves in high-cost areas such as the North Sea, with the ensuing addition of 5 million b/d to the world supply during the 1970s. Prices began to weaken early during the early 1980s—and as a means to stop the decline, in 1983 OPEC established the quota system. This strategy failed to stop the fall and prices collapsed in 1986.

"As a result of this process," said the PDVSA president, "by 1986 OPEC faced a drastically reduced market, in which its participation had shrunk from 30 million b/d to 16 million b/d, while prices had nose-dived from $35-$38/bbl to $12-$14/bbl."

Between 1983 and 1986, said Giusti, OPEC institutionalized a quota system, "based on the simplistic conclusion that oil prices could remain high by cutting back the output of its members. It is evident that this didn't occur."

In 1986 OPEC changed its focus, aiming at increasing market share, not with $35-$40/bbl oil, but with $18-$20/bbl oil, a move that opened new opportunities for its members. As a result, he said, "in an environment of competitive prices, world demand grew steadily, giving low-cost OPEC producers an increase in their market share. Today they produce about 28 million b/d, compared to a total world output of 45 million-46 million b/d." Under this market penetration approach, he added, "the quota system has become, in principle, contradictory. OPEC, in fact, has adopted a non-official policy that

del Occidente de Texas puede esperar un alto rendimiento de productos liviano y sólo 25% de residuos pesados, de bajo costo. Si la misma refinería sólo procesara crudos extrapesados, el rendimiento de residuo sería de 75%, volumen que convertiría la operación en un desastre económico.

Puesto que gran parte del crudo venezolano no tiene acceso directo al mercado mundial, agrega Giusti, Venezuela tuvo que elaborar "planes con visión de largo plazo y con una clara estrategia de penetración de mercados, la cual implica importantes inversiones en lo que se denomina conversión profunda para convertir grandes volúmenes de residuo pesado en productos mercadeables. La ejecución de ese tipo de proyectos toma 4 y hasta 6 años. Por eso, Venezuela jamás puede tener como estrategia de comercialización la de estar abriendo y cerrando producción, como sí lo pueden hacer los productores de crudos fungibles, tales como los del Mar del Norte, Arabia Saudita, Kuwait y otros productores del Medio Oriente.

La OPEP

Al analizar el papel que ha desempeñado OPEP desde que se fundara en 1960, Giusti afirma que durante la primera década de su existencia la organización tuvo modestos resultados dentro de su meta de lograr precios "justos" para sus miembros. "Durante la década de los años 1970, una serie de acontecimientos políticos en el Medio Oriente catapultó los precios del petróleo. El embargo unilateral de Libia en 1970, la guerra de Yom Kipur en 1973 y la revolución iraní en 1979, seguida del inicio de las hostilidades entre Irán e Irak, llenaron las arcas de los exportadores, convirtiendo en realidad las aspiraciones de la OPEP, mucho más allá de sus más optimistas expectativas."

El resultante aumento de precios afectó adversamente a los países productores porque las naciones importadoras adoptaron exitosamente programas para ahorrar energía y substituir el petróleo por otras fuentes de energía. Más aún, dice Giusti, los altos precios prohijaron el desarrollo de reservas en regiones de alto costo, tales como la del Mar del Norte, lo que a la postre significó 5 MM b/d de oferta adicional durante los años 1970. Los precios empezaron a debilitarse a principios de la década de 1980 y su colapso ocurrió en 1986.

Para entonces, la OPEP se enfrentaba a un mercado en el cual su participación había bajado de 30 MM b/d a 16 MM b/d y sus precios habían bajado de US$35-US$38/bl a US$12-US$14/bl. De 1983 a 1986, agrega Giusti, "la OPEP había institucionalizado un programa de cuotas, apoyada en la conclusión simplista de que se podrían mantener los elevados precios reduciendo el suministro de crudo de OPEP, cosa que evidentemente no ocurrió."

A partir de 1986, OPEP cambió de estrategia, esta vez "con la intención de penetrar mercados, ya no con un objetivo de US$35-US$40/bl, sino de alrededor de US$18-US$20/bl, y comenzó a brindarle nuevo espacio," afirma Giusti y agrega: "En un ambiente de precios competitivos, los países de la OPEP, productores de bajo costo, vieron aumentar su volumen. Actualmente producen unos 28

uld be termed as 'mixed' or even better defined, ıclear'."

While the organization maintained quotas and a pro-ction ceiling, exercising their sovereign right, individu-members choose to continue overproducing."

Saudi Arabia, for one, has increased its production ›m 5 million b/d in 1991 to 9.1 million b/d or more cur-ıtly, following a clear strategy of market penetration volume, achieved within an institution that it has tra-ionally dominated. The Saudi quota, self-imposed in e 1997, is 8.76-million b/d.

From 1990 to 1997, production increases gave nezuela an additional accumulated income of $24 bil-n—and $81 billion to Saudi Arabia. In 1997, nezuelan oil exports yielded a gross income of $17 bil-n, and those of Saudi Arabia $53 billion.

While there is no doubt that Saudi Arabia and nezuela represent the main driving forces within 'EC, their market penetration strategies differ drasti-ly. Saudi Arabia has achieved its expansion goals sed on its huge volumes of conventional crude. ıezuela's approach, on the other hand, has been quite ferent. Due to the very nature of its reserves in which avy crudes are predominant, said Giusti, Venezuela d to adopt "investment programs with long-range ion and commitments, achieving market expansion ıch more modestly by unilaterally increasing its mar-position." Clearly, he added, Venezuela can't afford to de by its 2.58-million b/d OPEC quota because, at that ume, a price of $18.50/bbl would be needed to fulfill country's needs, something that would be totally ossible.

"Venezuela's overproduction represents only 0.8% of world's total output. It can be stated, without any ubt, that Venezuela can't be blamed by the current rket situation." This had been caused by a 1.4-million drop in worldwide demand: 900,000 b/d due to the an economic crisis, and the balance by the 1997-1998 ıter in the Northern Hemisphere, one of the most ıign on record.

nezuela's Case

spite the fact that over the years Venezuela has offi-lly sanctioned OPEC's quota system, the fact remains, d Giusti, that his country "has been overproducing ing the last 10 years. Its current quota is 2.58 million , while its production capacity stands at 3.3 million , of which 338,000 b/d satisfy domestic demand and rest is exported. From 1990 to date, Venezuela's pro-ction has increased by 1.2 million b/d (24%), while t of Saudi Arabia has jumped by 4.9 million b/d %).

As for the current quota, Giusti said it's time "to ask y Venezuela should continue accepting a quota that y represents 9% of total production, assigned upon siderations arising during the predominance of the b countries at the end of the 1970s and the beginning he 1980s." ●

MM b/d de los 45-46 MM b/d que se producen en todo el mundo. Dentro de este nuevo ambiente de penetración de mercados, el sistema de cuotas resulta, en principio, contradictorio. La OPEP ha venido manejando una estrategia no oficial que puede calificarse de 'mixta,' aunque una manera más apropiada de definirla sería 'poco cara.' Se mantiene un sistema de cuotas...pero todos los países, ejerciendo su derecho soberano, han producido en exceso de sus cuotas."

Desde 1990, Arabia Saudita ha aumentado su producción, 4,9 MM b/d, "en una clara estrategia," dice Giusti, "de penetración por volumen, manejándola dentro de una institución que tradicionalmente ha dominado." Durante el mismo lapso, el aumento de producción de Venezuela fue de 1,2 MM b/d.

De 1990 a 1997, los aumentos de producción le dieron a Venezuela ingresos adicionales de US$24.000 MM—y de US$81.000 MM a Arabia Saudita. En 1997, las exportaciones venezolanas de petróleo rindieron un ingreso bruto de US$17.000 MM; y las de Arabia Saudita US$53.000 MM.

Aunque no cabe duda de que Arabia Saudita y Venezuela son los puntales principales de la OPEP, explica Giusti, sus estrategias de penetración de mercados son drásticamente diferentes. A tiempo que la de Arabia saudita se apoya en sus monumentales reservas de crudo convencional, Venezuela ha tenido que optar por otro enfoque porque "su base de reservas la obliga a implantar programas de inversión con visión y compromiso de largo plazo, y ha logrado ganar penetración adicional en forma mucho más modesta, ampliando unilateralmente su posición de mercado." Claramente, agrega Giusti, Venezuela no puede someterse a su cuota de 2,58 MM b/d a menos que pudiera vender su petróleo a US$18,50/bl para sostener el nivel de ingresos del país, cosa que es absolutamente imposible. A propósito de la cuota venezolana, Giusti dice que "vale la pena inquirir la razón por la cual Venezuela ha de continuar aceptando una cuota de apenas 9% de la producción total, constituida sobre consideraciones nacidas durante el predominio árabe de finales de los años 1970 y principios de los años 1980."

"La sobreproducción de Venezuela representa apenas 0,8% de la producción total del mundo. Se puede afirmar, sin lugar a dudas, que Venezuela no es la causante de la situación actual del mercado." Dicha situación de debe a una disminución de 1,4 MM b/d en el consumo mundial: 900.000 b/d a causa de la crisis económica del Asia y el resto debido al invierno de 1997-1998 en el Hemisferio Norte, el más benigno en muchos años.

En el caso venezolano, dice Giusti, oficialmente siempre ha habido un apego a las decisiones de OPEP en materia de cuotas, "Sin embargo, Venezuela ha venido sobreproduciendo desde hace unos 10 años. Actualmente tiene una cuota asignada de 2,58 MM b/d, mientras su capacidad es de más de 3,3 MM b/d, de los cuales 338.000 b/d se consumen en el territorio nacional y el resto va a la exportación." Desde 1990, la producción de Venezuela ha aumentado 1,2 MM b/d y la de Arabia Saudita 4,9 MM b/d (63%). ●

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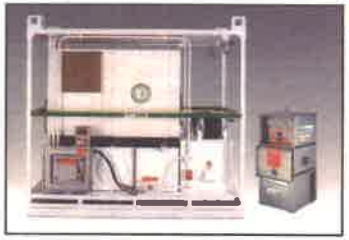

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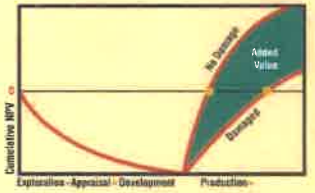

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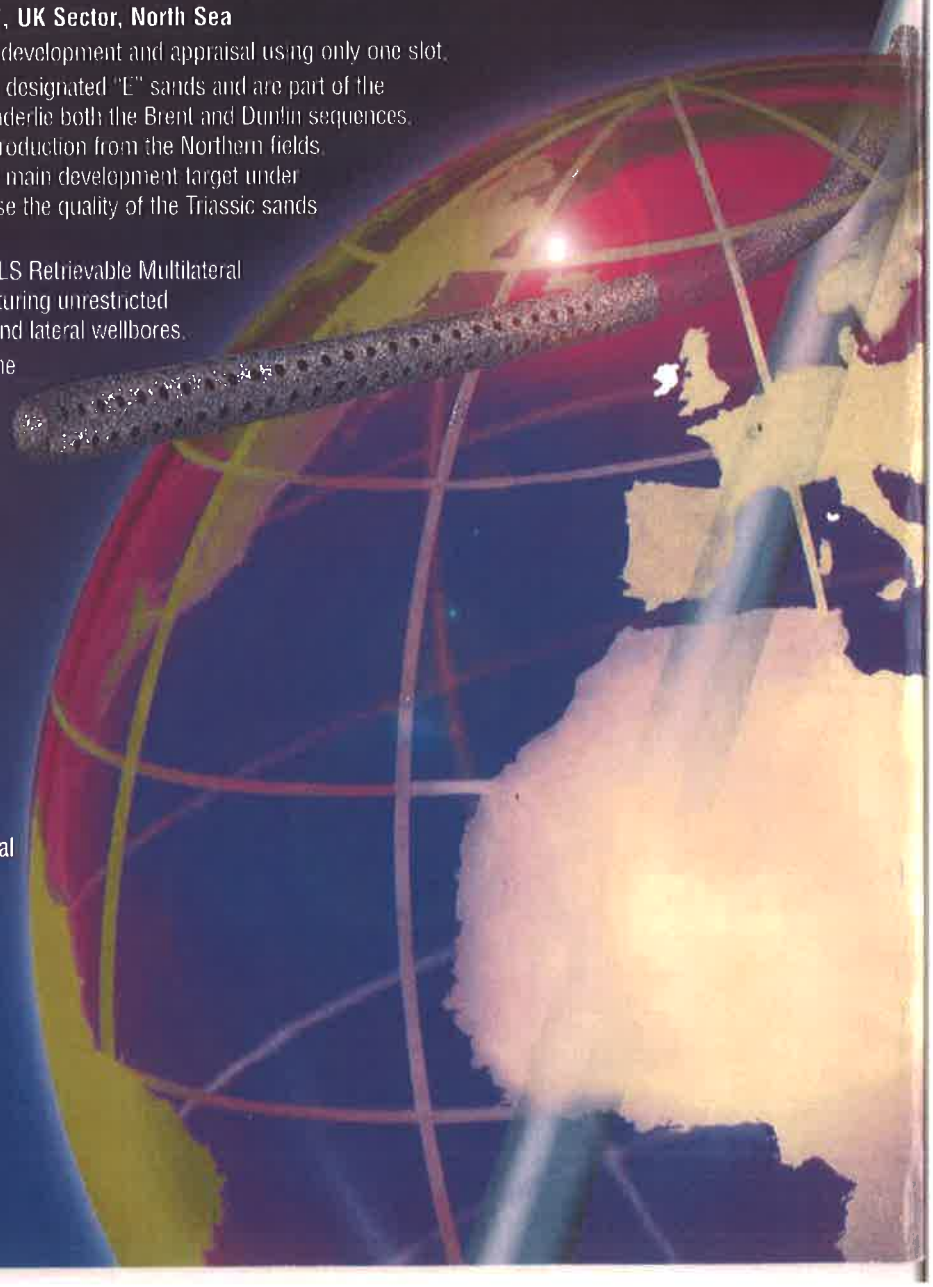

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