PDHonline Course C270 (3 PDH)

Advanced Oil & Gas Drilling Technology

Instructor: John Huang, Ph.D., PE and John Poullain, PE

2020

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5272 Meadow Estates Drive
Fairfax, VA 22030-6658
Phone: 703-988-0088
www.PDHonline.com

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TECHNOLOGY Locations: Canada (commercial) and United States (demonstration only)

CO_2-Sand Fracturing

SUMMARY

Fracturing has been widely used since the 1970s to increase production from formations with low permeability or wellbore damage. Unlike conventional hydraulic and acid fracturing techniques, CO_2-sand fracturing stimulates the flow of hydrocarbons without the risk of formation damage and without producing wastes for disposal. A mixture of sand proppants and liquid CO_2 is forced downhole, where it creates and enlarges fractures. Then the CO_2 vaporizes, leaving only the sand to hold the fracture open—no liquids, gels, or chemicals are used that could create waste or damage the reservoir. Any reservoir that is water-sensitive or susceptible to damage from invading fluids, gels, or surfactants is a candidate. The process has had widespread commercial success in Canada, and recent DOE-sponsored field tests have demonstrated commercial feasibility in the United States.

BLUEPRINT ON TECHNOLOGY

In widespread use in Canada, a stimulation technique now successfully demonstrated in the U.S. has outstanding results without formation damage

Using CO_2 to fracture oil and gas reservoirs

RECOMPLETING AND fracturing an existing oil or gas well to stimulate production that has declined over time is significantly less costly than drilling a new well. First used in the mid-1930s, fracturing treatments inject fluids under high pressure into the formation, creating new fractures and enlarging existing ones. "Proppants" (usually large-grained sand or glass pellets) are added to the fluid to support the open fractures, enabling hydrocarbons to flow more freely to the wellbore. Fracturing is widely used to stimulate production in declining wells and to initiate production in certain unconventional settings. More than one million fracturing treatments were performed by 1988, and about 35 to 40 percent of existing wells are hydraulically fractured at least once in their lifetime. More than eight billion barrels of additional oil reserves have been recovered through this process in North America alone. Yet conventional fracturing technology has drawbacks. The water- or oil-based fluids, foams, and acids used in traditional fracturing approaches can damage the formation—for instance, by causing clay in the shale to swell—eventually plugging the formation and restricting the flow of hydrocarbons. Conventional fracturing also produces wastes requiring disposal.

An advanced CO_2-sand fracturing technology overcomes these problems, and is proving a cost-effective process for stimulating oil and gas production. First used in 1981 by a Canadian firm, the process blends proppants with 100 percent liquid CO_2 in a closed-system-pressurized vessel at a temperature of 0°F and a pressure of 300 psi. Nitrogen gas is used to force the resulting mixture through the blender to the suction area of the hydraulic fracture pumping units and then downhole, where it creates and enlarges fractures. The CO_2 used in the process

ECONOMIC BENEFITS

- Eliminates hauling, disposal, and maintenance costs of water-based systems
- Can significantly increase well productivity and ultimate recovery
- CO_2 vaporization leads to fast cleanup, whereas water-based fluids sometimes clean up slowly, reducing cash flow
- Recovery of valuable oil and gas is optimized

ENVIRONMENTAL BENEFITS

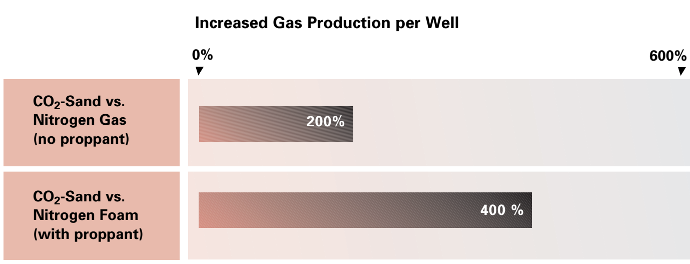
- Using liquid CO_2 creates long, propped fractures without formation damage
- No wastes requiring disposal are created
- Conventional fracturing gels and chemicals, which may damage the flow path between wellbore and formation, are not used
- Groundwater resources are protected

vaporizes, leaving behind a dry, damage-free proppant pack. The technology has gained widespread commercial acceptance in Canada, where it has been used some 1,200 times. In the United States, use has been limited to demonstrations—many sponsored and cofunded by DOE—taking place over the last two years in about 50 wells in Kentucky, Ohio, Pennsylvania, Tennessee, Texas, New York, Colorado, and New Mexico.

CO_2-sand fracturing treatments average from $30,000 to $50,000, depending on well depth and rock stresses. While often higher-cost than conventional methods, these costs are offset by savings realized through eliminating both swab rigs and the hauling, disposal, and maintenance costs associated with water-based systems. As in conventional fracturing, CO_2-sand treatments can significantly increase a formation's production and profitability.

METRICS

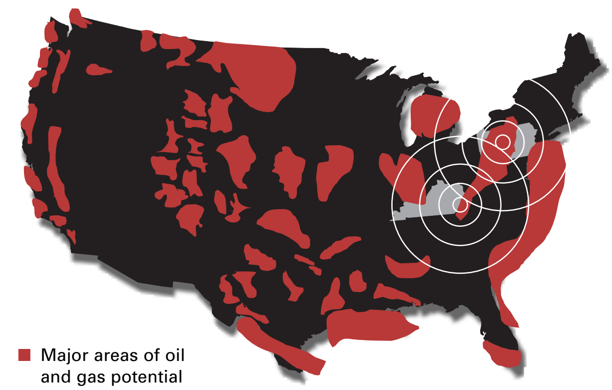
Results of fracturing technique tests in Devonian Shales wells after 37 months



Source: Arnold, Hart's Petroleum Engineer International, January 1998

CASE STUDIES

Success in the Field



Successful DOE-sponsored field tests

The U.S. Geological Survey estimates that 200 to 400 trillion cubic feet of natural gas resources exists in unconventional settings in the United States. Developing cost-effective advanced fracturing techniques is crucial in our quest to recover these resources. A number of field-test fracturing projects sponsored by DOE recently evaluated and proved CO_2-sand technology's effectiveness in gas recovery. In the Devonian Shales in Kentucky, four of 15 gas wells were stimulated with CO_2-sand mixture, seven with nitrogen gas and no proppant, and four with nitrogen foam and proppant. After 37 producing months, wells stimulated with the CO_2-sand process had produced four times as much as those treated with foam, and twice as much as those stimulated with nitrogen gas. In central Pennsylvania, three gas wells were stimulated using CO_2-sand fracturing. Immediately after fracturing, two of the wells exhibited production increases of 1,000 percent and 600 percent. Over a year and a half later, production from the wells had increased 620 percent, 300 percent, and 240 percent, respectively.

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CONTACT

U.S. Department of Energy
Office of Fossil Energy
1000 Independence Avenue, SW
Washington, DC 20585

Elena S. Melchert
(202) 586-5095
elena.melchert@hq.doe.gov

Trudy A. Transtrum
(202) 586-7253
trudy.transtrum@hq.doe.gov

TECHNOLOGY Locations: Worldwide, onshore and offshore

Coiled Tubing

SUMMARY

Continuous coiled tubing can dramatically increase the efficiency, profitability, and productivity of drilling for oil and gas. Whereas in conventional drilling operations, the drilling pipe consists of several jointed pieces requiring multiple reconnections, a more flexible, longer coiled pipe string allows uninterrupted operations. A cost-effective alternative for drilling in reentry, underbalanced, and highly deviated wells, coiled tubing technology minimizes environmental impacts with its small footprint, reduced mud requirements, and quieter operation. Quick rig set-up, extended reach in horizontal sidetracking, one-time installation, and reduced crews cut operating costs significantly. For multilateral and slimhole reentry operations, coiled tubing provides the opportunity for extremely profitable synergies.

BLUEPRINT ON TECHNOLOGY

Successively better coiled tubing technologies drive improvements in cost, productivity, and efficiency of drilling operations, while reducing environmental impact

A strong portfolio of benefits

Particularly valuable in sensitive environments such as Alaska's North Slope, coiled tubing technology has far less impact on a drilling site than conventional equipment, in addition to performing drilling operations more efficiently and cost-effectively. Although the first coiled tubing units were built in the 1950s, only after rapid technological advances in the late 1980s did the technology start to gain industry-wide recognition. From 533 operating units in 1992, usage has grown to some 730 units in 1998, and many drilling companies are now revising their rig portfolios.

In a variety of drilling applications, coiled tubing eliminates the costs of continuous jointing, reinstallation, and removal of drilling pipes. It is a key technology for slimhole drilling, where the combination can result in significantly lower drilling costs—a typical 10,000-foot well drilled in southwest Wyoming costs about $700,000, but with coiled tubing and slimhole, the same well would cost $200,000 less.

Reduced working space—about half of what is required for a conventional unit—is an important benefit, as are reduced fuel consumption and emissions. A significant drop in noise levels is also beneficial in most locations. The noise level at a 1,300-foot radius is 45 decibels, while at the same radius a conventional rig has a 55-decibel level.

ECONOMIC BENEFITS

- Increased profits, in certain cases, from 24-hour rig set-up and faster drilling
- Smaller drilling infrastructure and more stable wells
- No interruptions necessary to make connections or to pull production tubing
- Reduced waste disposal costs
- Reduced fuel consumption
- Increased life and performance from new rig designs and advanced tubulars, reducing operating costs

ENVIRONMENTAL BENEFITS

- Reduced mud volumes and drilling waste
- Cleaner operations, as no connections to leak mud
- Reduced operations noise
- Minimized equipment footprints and easier site restoration
- Reduced fuel consumption and emissions
- Less visual impact at site and less disturbance, due to speedy rig set-up
- Reduced risk of soil contamination, due to increased well control
- Better wellbore control

Technology advances in the '90s

Dramatic advances have recently brought new coiled tubing technology to market. For example, new designs from leading drilling service companies have eliminated coiled tubing rigs' guide arches; in these new designs, eliminating the bending in the tubing at the guide arch has significantly increased its life. The newest advance is an electric bottomhole assembly offering immediate data feedback on bottomhole conditions, reduced coiled tubing fatigue, maintenance of bit speed independent of flow rate, and improved reliability. New materials like advanced titanium alloys and advanced metal-free composites have improved the reliability, performance, corrosion-resistance, weight, and cost-effectiveness of coiled tubing assemblies. In certain cases, titanium tubing offers an estimated reeling cycle life 5 to 10 times greater than steel.

Photo: WZI, Inc.

CASE STUDIES

Success in the Field

At Lake Maracaibo field

Advanced coiled tubing drilling is helping operators optimize resource recovery at Venezuela's Lake Maracaibo field. Baker Hughes INTEQ's first-of-its kind Galileo II hybrid drilling barge, containing 2⅜-inch coiled tubing and slimhole drilling measurement-while-drilling tools, drilled its first well at the end of 1997. It was the first time an underbalanced well had been drilled on Lake Maracaibo, and it promises good results. Galileo II's unique design is also expected to significantly increase the life of its coiled tubing, ultimately reducing operating costs. Operating in a fragile lake ecosystem presents unique waste management challenges, and all drill cuttings and waste mud are transported back to shore for disposal.

METRICS

Field trials in the Netherlands demonstrate environmental benefits

Fuel Consumption and Gas Emissions:
Coiled Tubing vs. Conventional Rigs

		Med Workover Rig	Land Drilling Rig	Coiled Tubing Drilling Unit	
Diesel m³/month			35	160	25
Gas Emissions kg/day	CO_2	3,293	15,055	2,122	
	CO	3.7	16.8	2.5	
	NO_x	4.6	21	2.1	
	HC	3.9	17.8	2.8	
	HC (Gas)	1.8	8.4	1.1	
	SO_2	4.2	19.4	2.2	

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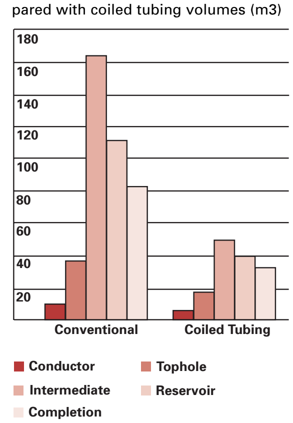
Conventional drilling fluids volume compared with coiled tubing volumes (m3)



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CONTACT

U.S. Department of Energy
Office of Fossil Energy
1000 Independence Avenue, SW
Washington, DC 20585

Elena S. Melchert
(202) 586-5095
elena.melchert@hq.doe.gov

Trudy A. Transtrum
(202) 586-7253
trudy.transtrum@hq.doe.gov

TECHNOLOGY Locations: Worldwide, onshore and offshore

Horizontal Drilling

SUMMARY

Horizontal drilling targets oil or gas in thin, tight reservoirs, reservoirs inaccessible by vertical drilling, and reservoirs where horizontal wellbores significantly increase flow rates and recovery. Horizontal wells maximize utilization of drilling sites and infrastructure. While vertical wells drain oil from a single hole and have limited contact with oil-bearing rock, horizontal wells penetrate a greater cross-section of the formation, allowing substantially more oil to drain. A horizontal well is drilled laterally from a vertical wellbore at an angle between 70° and 110°. It can tap the hydrocarbon supplies of a formation without further environmental disturbance, of particular value in sensitive areas.

BLUEPRINT ON TECHNOLOGY

Without any increase in environmental impact, horizontal drilling allows developers to reach reserves beyond the limits of conventional techniques

Breaking geologic barriers

The current boom in horizontal drilling is due to rapid developments in technology over the past two decades. Although several horizontal wells were successfully drilled between the 1930s and 1950s, these were limited to expensive 100- to 200-foot forays. Interest waned in such onshore applications after the development of hydraulic fracturing technology made vertical wells more productive. The offshore industry continued to pursue horizontal drilling, but the limitations of the available equipment often resulted in ineffective, expensive, and time-consuming drilling operations.

In the mid-1970s, several significant technology advances started breaking down these barriers. Steerable downhole motor assemblies, measurement-while-drilling (MWD) tools, and improvements in radial drilling technologies were the breakthroughs needed to make horizontal drilling feasible. Short-radius technology had been developed in the 1930s, the earliest curvature technique used to drill laterals; in the 1950s, long-radius technology allowed lateral displacement away from the rig to penetrate the reservoir. Then, in the 1970s, medium-radius techniques permitted re-drilling horizontal intervals from existing wellbores, and with this advance producers could build rapidly to a 90° angle. Today, horizontal wells are being drilled longer and deeper, in more hostile environments than ever before.

Horizontal drilling is now conventional in some areas and an important component of enhanced recovery projects. At any given time, horizontal drilling accounts for 5 to 8 percent of the U.S. land well count. The Austin Chalk field has been the site of over 90 percent of the onshore horizontal rig count since the late 1980s, and still accounts for the majority of horizontal permits and rig activity in the U.S. today. Thirty percent of all U.S. reserves are in carbonate formations, and it is here that 90 percent of horizontal wells are drilled.

ECONOMIC BENEFITS

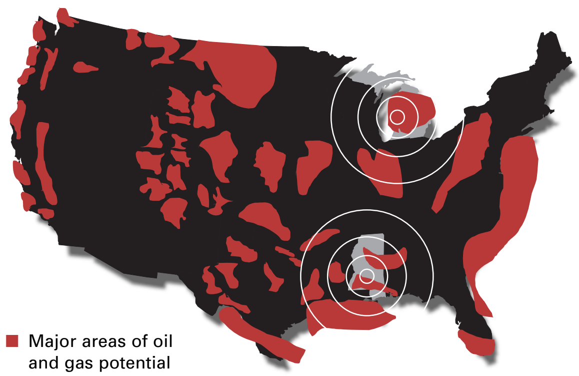
- Increased recoverable hydrocarbons from a formation, often permitting revitalization of previously marginal or mature fields
- More cost-effective drilling operations
- Less produced water requiring disposal and less waste requiring disposal
- Increased well productivity and ultimate recovery

ENVIRONMENTAL BENEFITS

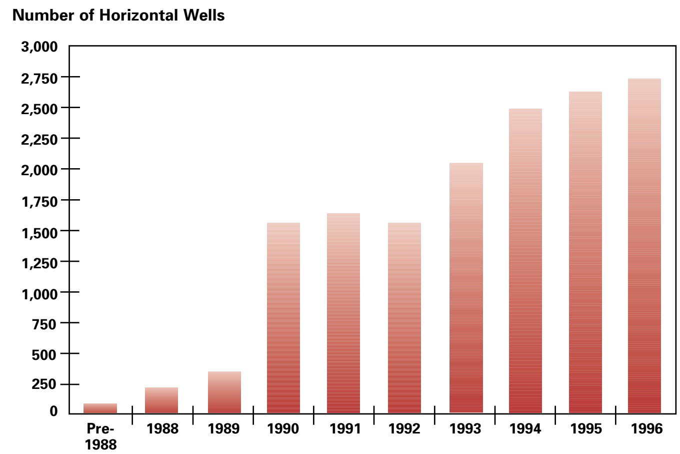
- Less impact in environmentally sensitive areas
- Fewer wells needed to achieve desired level of reserve additions
- More effective drilling means less produced water
- Less drilling waste

CASE STUDIES

Success in the Field



Worldwide Horizontal Wells



Source: *Oil & Gas Journal, November 23, 1998*

Success in the Black Warrior Basin

In 1993, after six years of production, the Goodwin gas field in the Black Warrior Basin was converted to gas storage by the Mississippi Valley Gas Co. Only conventional vertical wells had been drilled in the thin (10 feet), tight, abrasive formation. The operator successfully drilled and completed the first horizontal well in only 23 days, utilizing MWD and gamma ray tools, a short radius motor, and a polycrystalline diamond bit. Overall costs approached twice that of a conventional well in the field, but the deliverability of the horizontal well was six times that of a vertical well. Since one horizontal well is producing the equivalent of six vertical wells, maintenance and operating costs are lower, and fewer meter runs, flowlines, and other facilities are required.

New reserves in the Dundee Formation

Only 15 percent of the known oil located in the Michigan Basin's Dundee Formation had been produced when a DOE co-sponsored horizontal drilling project brought new life to the formation's exhausted Crystal field. The new horizontal well now produces nearly 20 times more than the best conventional well in its field—100 barrels of oil a day—and boasts estimated recoverable reserves of 200,000 barrels. Success has spawned the drilling of nine other horizontal wells here, and nearly 30 others in geologically similar fields in the basin. If successful in other depleted Dundee fields, horizontal wells could produce an additional 80 to 100 million barrels of oil, worth about $210 million in tax revenues alone.

METRICS

In the United States, according to a recent DOE study, horizontal drilling has improved:

- Potential reserve additions—by an estimated 10 billion barrels of oil equivalent, nearly 2% of original oil-in-place
- The average production ratio—now 3.2:1 for horizontal compared to vertical drilling based on field data, even though the average cost ratio is 2:1
- Carbonate numbers are even better—production is nearly 400% greater than vertical wells, yet costs are only 80% more

Source: U.S. Department of Energy and Maurer Engineering, Inc., 1995

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CONTACT

U.S. Department of Energy
Office of Fossil Energy
1000 Independence Avenue, SW
Washington, DC 20585

Elena S. Melchert
(202) 586-5095
elena.melchert@hq.doe.gov

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TECHNOLOGY Locations: Worldwide, onshore and offshore

Hydraulic Fracturing

SUMMARY

Routinely applied to over half of U.S. gas wells and a third of oil wells, hydraulic fracturing has been proven to enhance well performance, minimize drilling, and recover otherwise inaccessible resources. It makes the development of some low-permeability, tight formations and unconventional resources economically feasible. When the flow of hydrocarbons is restricted by formation characteristics, injecting pressurized fluids and solid additives can stimulate wells to increase production. Fluids are pumped into the formation at pressure great enough to fracture the surrounding rock. A proppant slurry follows, biodegrading to sand proppant that holds the fractures open, allowing free passage of fluids to the wellhead. So successful has this technology been that the industry currently spends a billion dollars annually on hydraulic fracturing.

BLUEPRINT ON TECHNOLOGY

Assisting operators to bring new life to mature fields and make unconventional fields commercially viable

Stimulating wells to deliver more

First introduced in 1947, hydraulic fracturing quickly became the most commonly used technique to stimulate oil and gas wells, ultimately enabling production of an additional eight billion barrels of North American oil reserves that would otherwise have been unrecovered. By 1988, fracturing had already been applied nearly a million times. Each year, approximately 25,000 gas and oil wells are hydraulically fractured.

Fracturing is generally used to regain productivity after the first flow of resources diminishes. It is also applied to initiate the production process in unconventional formations, such as coalbed methane, tight gas sands, and shale deposits. Improvements in fracturing design and quality control have enabled operators to successfully apply fracturing techniques in more complex reservoirs, hostile environments, and other unique production settings.

New advances

The DOE-led Natural Gas and Oil Technology Partnership has promoted many of this decade's fracturing advances. These include the use of air, underbalanced drilling, and new fracturing fluids to reduce formation damage and speed well cleanup. Improved log interpretation has improved identification of productive pay zones. Improved borehole tools help map microseismic events and predict the direction and shape of fractures. New 3-D fracture simulators with revised designs and real-time feedback capabilities improve prediction of results.

Advanced breakers and enzymes that minimize the risk of formation plugging from large-volume hydraulic stimulations are the latest advances to protect the environment and increase ultimate recovery. In addition, emerging technologies developed by DOE and the Gas Research Institute, such as microseismic fracture mapping and downhole tiltmeter fracture mapping, offer the promise of more effective fracture diagnostics and greater ultimate resource recovery.

ECONOMIC BENEFITS

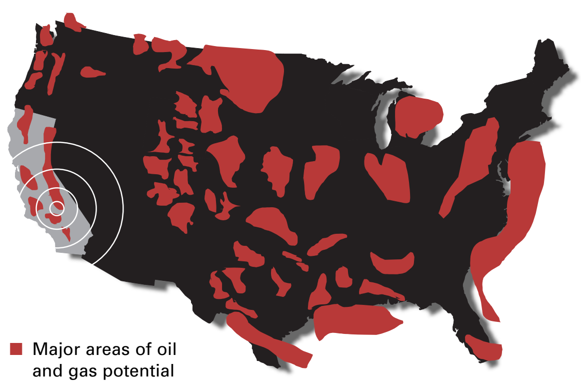
- Increased well productivity and ultimate recovery
- Significant additions to recoverable reserves
- Greatly facilitated production from marginal and mature fields

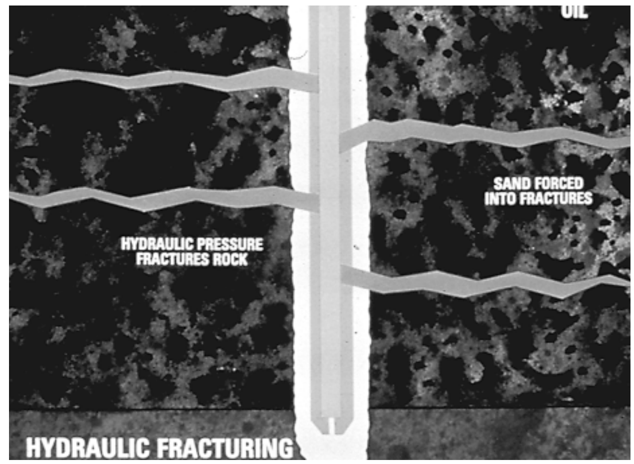
ENVIRONMENTAL BENEFITS

- Optimized recovery of valuable oil and gas resources
- Protection of groundwater resources
- Fewer wells drilled, resulting in less waste requiring disposal

CASE STUDIES

Success in the Field





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Increased profits from the once declining Lost Hills field

Refined fracturing methods and improved quality control have brought increased productivity and profitability to a field that once resisted development. The Lost Hills field in California contains an estimated two billion barrels of oil-in-place, but since its discovery in 1920 it has produced only a fraction of its potential. The field has very low permeability and it lacks a strong natural fracture network, which restricts the flow of resources. This makes the field difficult to produce at acceptable rates without fracture stimulation.

Although hydraulic fracturing began in Lost Hills during the ’60s and ’70s, completion results were poor because of small proppant volumes and inefficient fracture fluids. Between 1987 and 1990, Chevron initiated massive hydraulic fracture stimulation. Although productivity increased significantly, costs were high and the work was not as profitable as anticipated.

In 1990, Chevron and Schlumberger Dowell formed a partnership aimed at improving fracturing efficiency, reducing costs, and increasing productivity. One result is that multiple wells are now stimulated from fixed equipment locations. Since its implementation in late 1992, this central site strategy has been used to fracture more than 100 wells, using some 200 million pounds of proppant. The strategy has lowered costs by reducing personnel, well completion time, and equipment mobilization, while improving environmental management and safety controls. Along with fracture design changes, this has reduced overall fracturing costs by 40 percent since 1988. These efforts played a large part in the field’s 250 percent production increase between 1989 and 1994—from 6,000 barrels to more than 15,000 barrels of oil per day.

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CONTACT

U.S. Department of Energy
Office of Fossil Energy
1000 Independence Avenue, SW
Washington, DC 20585

Elena S. Melchert
(202) 586-5095
elena.melchert@hq.doe.gov

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TECHNOLOGY Locations: Worldwide, onshore and offshore

Measurement-While-Drilling

SUMMARY

Measurement-while-drilling (MWD) systems measure downhole and formation parameters to allow more efficient, safer, and more accurate drilling. These measurements can otherwise be obtained only by extrapolation from surface measurements. MWD systems calculate and transmit real-time data from the drill bit to the surface, avoiding the time-lag between occurrence and surface assessment and significantly improving drilling safety and efficiency. Without this analysis of bottomhole conditions, it is sometimes necessary to abandon a hole for a new start. MWD reduces both costs and environmental impacts because measurements and formation evaluation occur before formation damage, alteration, or fluid displacement have occurred. Of particular use in navigating hostile drilling environments, MWD is most frequently used in expensive exploratory wells, and in offshore, horizontal, and highly deviated wells.

BLUEPRINT ON TECHNOLOGY

High-tech tools that deliver real-time bottomhole data prevent excessive formation damage and make drilling significantly more precise and cost-effective

More information for better drilling

MWD TECHNOLOGY is critical as operators seek to reach deeper and farther for new hydrocarbon resources. A real-time bit navigation and formation evaluation aid, MWD uses tools such as triaxial magnetometers, accelerometers, and pressure sensors to provide vital downhole data concerning directional measurements, pore pressures, porosity, and vibration. This provides for more effective geosteering and trajectory control, and safer rig operations. Novel equipment transmits bottomhole information to the surface by encoding data as a series of pressure pulses in the wellbore's mud column or by electromagnetic telemetry. Surface sensors and computer systems then decode the transmitted information and present it as real-time data.

In normal drilling environments, MWD is used to keep the drill bit on course. MWD is also valuable in more challenging drilling environments, including underbalanced, extended-reach, deviated, and high-pressure, high-temperature drilling. In underbalanced directional drilling, MWD monitors the use of gas injected to maintain safe operating pressure. In deviated and horizontal wells, MWD can be used to geologically steer the well for maximum exposure in the reservoir's most productive zones.

Evaluating the formation

Prior to the spread of MWD systems in the late '70s, bottomhole conditions were monitored by time-consuming analysis of cuttings and gas intrusion, and by after-the-fact wireline steering measurement that necessitated frequent interruptions for pipe removal. Today, the continuous flow of MWD information improves formation evaluation efforts as well as drilling progress. Over successive periods, MWD data can reveal dynamic invasion effects, yielding information on hydrocarbon mobility, gas-oil-water contact points, and formation porosity. Future advances in MWD technology, such as MWD acousticalipers with digital signal processing

ECONOMIC BENEFITS

- Improved drilling efficiency and accuracy
- Timely formation evaluation
- Reduced operating costs and financial risks
- Improved rig safety

ENVIRONMENTAL BENEFITS

- Less formation damage
- Reduced possibility of well blowouts and improved overall rig safety
- Reduced volume of drilling waste as fewer wells drilled overall
- Better wellbore control

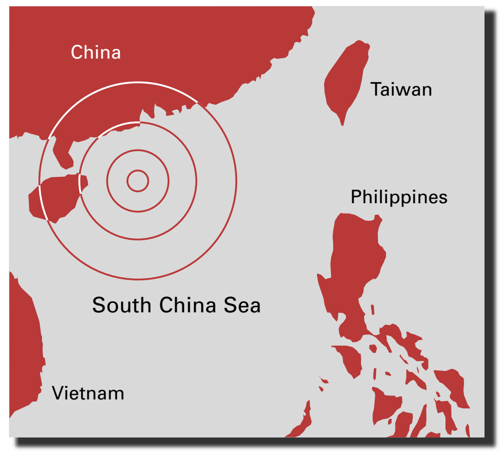
and DOE-sponsored research into ultra-deepwater MWD technologies, promise to enhance operations even further.

Contributing dramatically to operational safety

Operators seeking to control drilling operations and enhance rig safety in difficult environments such as deepwater drilling find MWD a valuable tool. In combination with advanced interpretive software applications, MWD is helping deepwater operators better forecast and measure a formation's pore and fracture pressures. More accurate geopressure estimates can prevent dangerous well blowouts and fires. In the unlikely event of a deepwater blowout, MWD equipment is a crucial tool in assisting operators to drill and steer a relief well to regain control of the well.

CASE STUDIES

Success in the Field



Extended reach in the South China Sea

In the South China Sea, MWD technology was critical in helping operators drill a 5-mile extended-reach well to a then world-record horizontal displacement of nearly 26,500 feet, at a true vertical depth of approximately 10,000 feet. It effectively "steered" the well to access the most productive zones at a final hole angle of 54°. In combination with other advanced drilling and completion technologies, MWD technology permitted operators to access this otherwise uneconomical, remote offshore field, completing the project in approximately 100 days at a cost of $24 million. As of June 1997, this once-bypassed field was producing 7,000 barrels of oil per day.

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CONTACT

U.S. Department of Energy
Office of Fossil Energy
1000 Independence Avenue, SW
Washington, DC 20585

Elena S. Melchert
(202) 586-5095
elena.melchert@hq.doe.gov

Trudy A. Transtrum
(202) 586-7253
trudy.transtrum@hq.doe.gov

TECHNOLOGY Locations: Worldwide, onshore and offshore

Modern Drilling Bits

SUMMARY

Dramatic advances in drill bit technology have improved drilling performance significantly while cutting wastes and environmental impacts. Although the choice of bit represents only 3 percent of the cost of well construction, bit performance indirectly affects up to 75 percent of total well cost. Faster rates of penetration and greatly extended bit life, the result of advances in materials technology, hydraulic efficiency, cutter design, and bit stability, now allow wells to be drilled more quickly, more profitably, and with less environmental impact. The improvement to an operator's cost-efficiency from these advances is striking. Today, selection of the appropriate bit has become critical both in establishing the overall economics of field development and in minimizing the environmental impacts of drilling.

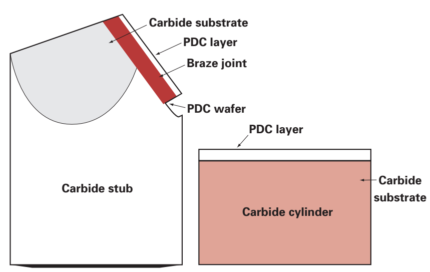
BLUEPRINT ON TECHNOLOGY

Evolving bit technology allows operators to drill wellbores more quickly and with less environmental impact

The diamond success story

FROM USE IN ONE percent of total worldwide drilling in 1978, to an estimated 25 percent in 1997, diamond drill bits, which use cutters consisting of a thick layer of tungsten carbide permeated with bonded diamond particles, have been one of the success stories of the last 25 years. Natural diamonds, synthetic diamonds, and diamond composites are now routinely used within insert-bit cutting structures, and, although originally developed for hard formations, polycrystalline diamond compact (PDC) bits have proved their value in soft- and medium-hard formations too. Today, PDC bits are most applicable in areas with relatively soft formations or where drilling is expensive, such as offshore locations and remote wells. In parallel with PDC development, roller cone bits have also been improved. The National Petroleum Council estimates that improvements in drilling efficiency from advances such as those in bit technology have reduced underlying drilling costs by about 3 percent annually over the last 50 years. As materials technology, hydraulics, and bit stability continue to improve, so will drilling performance and environmental protection.

PDC Cutter Components



Source: Petroleum Engineer International, 1993

Matching the bit to the formation

By helping operators choose the best bit for the job, computerized drill bit optimization systems have improved the way bits are being selected and used. These systems match an individual formation to the most effective milled-tooth, tungsten carbide insert and PDC bit to complete the job for the least cost per foot. They also prescribe other design parameters such as hole gauge and hydraulic requirements to help determine optimal cutting structure.

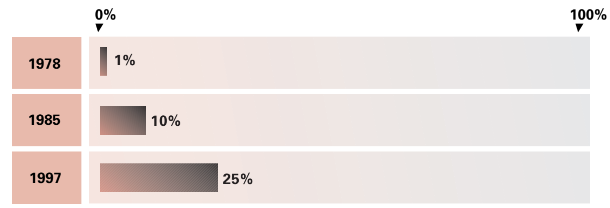
ECONOMIC BENEFITS
Increased rates of penetration
Fewer drilling trips due to greater bit life
Reduced power consumption
Improved drilling efficiency and hence viability of marginal resources

ENVIRONMENTAL BENEFITS
Reduced power use and resultant emissions
Less drilling waste
Reduced equipment mobilization and fewer rigs
Less noise pollution
Better wellbore control and less formation damage

Metrics

Increases in diamond bit drilling

In 1978, approximately 1 percent of the total footage drilled worldwide was drilled with diamond bits; in 1985, it was approximately 10 percent; by 1997, that figure was an estimated 25 percent. Also, between 1988 and 1994, advances in PDC technology increased the average footage drilled by over 260 percent, from approximately 1,600 feet to 4,200 feet per PDC bit.



Source: Rappold, Oil & Gas Journal, 8/14/95

Case Studies

Success in the Field

Switching to new drill bits saves time and money

Using a specialized bit optimization system, Anadarko Petroleum has demonstrated significant efficiency improvements. For example, drilling time was reduced by 8 to 12 days in Algeria, with savings of $250,000 to $350,000; and a Mississippi project saved 15 days and $200,000. Ultimately, impacts on the environment were appreciably lessened.

Petroleum Development Oman found that rates of penetration dropped from 26 feet per hour to under 10 feet per hour when drills using tungsten carbide inserts hit the hard Khuff Formation. Switching to a new generation PDC bit with carbide-supported edge cutters resulted in a new rate of 23.6 feet per hour in the Khuff. The entire section was drilled in one run, at half the cost of the same section in a similar well. Another well drilled in the comparable Zauliayah field resulted in a rate of 34 feet per hour at a cost of $34 per foot, nearly half the cost of drilling a comparable well in the area with an earlier-generation bit.

When Chevron switched to new generation polycrystalline bits at its Arrowhead Greyburg field in New Mexico, the rate of penetration increased more than 100 percent. Chevron had been experiencing problems using 3-cone bits and thermally stabilized diamond bits. Switching to PDC bits with curved cutters significantly increased drilling efficiency, while reducing environmental impacts.

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Contact

U.S. Department of Energy
Office of Fossil Energy
1000 Independence Avenue, SW
Washington, DC 20585

Elena S. Melchert
(202) 586-5095
elena.melchert@hq.doe.gov

Trudy A. Transtrum
(202) 586-7253
trudy.transtrum@hq.doe.gov

TECHNOLOGY Locations: Worldwide, onshore and offshore

Multilateral Drilling

SUMMARY

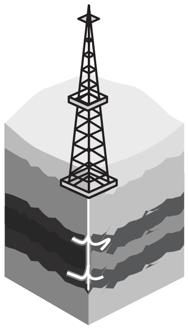
Multilateral drilling creates an interconnected network of separate, pressure-isolated, and reentry-accessible horizontal or high-angle wellbores surrounding a single major wellbore, enabling drainage of multiple target zones. In many cases, this approach can be more effective than simple horizontal drilling in increasing productivity and enlarging recoverable reserves. Often multilateral drilling can restore economic life to an aging field. It also reduces drilling and waste disposal costs. Today, in a wide variety of drilling environments, both onshore and offshore, from the Middle East to the North Sea and from the North Slope to the Austin Chalk, multilateral completions are providing dramatic returns for operators.

BLUEPRINT ON TECHNOLOGY

New lateral drilling developments provide dramatic returns for operators, with less waste, smaller footprints, and increased site protection

From horizontal to multilateral branching wellbores

Horizontal drilling provoked a surge of interest in the 1980s as a way to contact more oil reserves, penetrating a greater cross-section of the oil-bearing rock with a single wellbore and intersecting repeatedly the fractures that carry oil to a producing well. Today, declining production, flat prices, and heightened environmental awareness have led the exploration and production industry to develop advanced drilling and completion technologies that permit wells to branch out multilaterally, in certain cases saving both time and money compared to horizontal drilling. In many cases, such as deep reservoir production, it is more efficient to create a connected network than to drill multiple individual horizontal wellbores.



Multilateral drilling is of greatest value in reservoirs that:

- Have small or isolated accumulations in multiple zones
- Accumulate oil above the highest existing perforations
- Have pay zones that are arranged in lens-shaped pockets
- Are strongly directional
- Contain distinct sets of natural fractures
- Are vertically segregated, with low transmissibility

ECONOMIC BENEFITS

- Improved production per platform
- Increased productivity per well and greater ultimate recovery efficiency
- New life for marginally economic fields in danger of abandonment
- Reduced drilling and waste disposal costs
- Reduced field development costs
- Improved reservoir drainage and management
- More efficient use of platform, facility, and crew

ENVIRONMENTAL BENEFITS

- Fewer drilling sites and footprints
- Less drilling fluids and cuttings
- Protection of sensitive habitats and wildlife

CASE STUDIES

Success in the Field

"[With advanced re-entry multilateral technology] we are seeing the potential to reduce by half the costs associated with subsea developments. In some cases, this will make what were previously marginal or non-economic discoveries economical."

ALI DANESHY
Vice President, Halliburton

Norsk demonstrates the future of offshore drilling

A highly successful offshore project in Norway is showcasing the reduced environmental impacts and increased economic benefits of multilateral completions. In March 1997, Norsk Hydro a.s. and Halliburton Energy Services drilled the world's first subsea multilateral with reentry access in Norsk's Troll field. The companies estimate that the economic benefits will be 50 percent greater than those from fixed platforms. By reducing the systems required to access the subsea reservoir, the project cuts both costs and impact on the environment and leads the way for subsequent offshore drilling operations.

New life for old wells: pentalateral drilling in the Middle East

Mounting evidence demonstrates that multilaterial drilling can bring new life to old wells. In the Arabian Gulf recently, a significant reduction in production that may have spelled well closure in the past was instead the stimulus to drill five lateral branches into new pay zones. The lateral wells were drilled in only 19 days, reaching some 5,000 feet of new producing formations. Since the new zones consisted of relatively soft limestone layers separated from each other by dolomites, drilling presented few problems. Dramatically increased production rates covered costs in just six days. In all, production increased 2.7 times as a result of the multilateral completions.

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CONTACT

U.S. Department of Energy
Office of Fossil Energy
1000 Independence Avenue, SW
Washington, DC 20585

Elena S. Melchert
(202) 586-5095
elena.melchert@hq.doe.gov

Trudy A. Transtrum
(202) 586-7253
trudy.transtrum@hq.doe.gov

TECHNOLOGY

Locations: Deepwater—Gulf of Mexico, West Africa, North Sea, Brazil, others

Offshore Drilling

SUMMARY

Recent exploration successes in deepwater plays in the Gulf of Mexico are of crucial importance in providing a vital new domestic resource. Technological advances are increasing operators' ability to take advantage of these finds, while reducing the dangers and uncertainty inherent in deepwater operations. Without such progress, much of the Gulf's resources may remain undeveloped. A major concern for operators is the safety of deepwater exploratory operations, especially as the industry moves toward depths of 10,000 feet. To ensure stability and efficiency at such depths, advanced dynamic positioning technology is now being used. This includes thruster units and sophisticated computer and navigation systems to hold a new generation of drillships, floating production, storage, and offloading systems, and survey vessels on location without anchors or mooring lines.

BLUEPRINT ON TECHNOLOGY

Technology advances in dynamic positioning expand opportunities for deepwater drilling with reduced environmental impact

Deepwater opportunities

THE GULF OF MEXICO'S deepwater reservoirs have become America's new frontier for oil and gas exploration. Production potential from proved and unproved reserves in deepwater areas is estimated to be roughly 1.8 billion barrels of oil and 5.8 trillion cubic feet of natural gas. Consequently, drilling in the Gulf's Outer Continental Shelf has increased greatly over the last 10 years. Today, deepwater drilling from permanent structures and wildcat wells is at an all-time high. In October 1997, a record 31 temporary and permanent deepwater rigs were drilling in water depths greater than 1,000 feet, as compared to only nine in 1990.

Production from deepwater wells is increasing too. In 1985, for example, less than 2 percent of the Gulf's total oil production was from deepwater wells. By 1996, over 17 percent of the Gulf's oil production came from deepwater wells. Natural gas production from deepwater areas in the Gulf has also increased—from less than 1 percent of total production in 1985—to nearly 6 percent in 1996.

Improving station keeping

Dynamic positioning systems compensate for the effects of wind, waves, and current, enabling mobile offshore drilling units to hold position over the borehole, maintaining within operational limits lateral loads on the drill stem and marine riser. Improved dynamic positioning systems, in combination with improved onboard motion compensation systems, are expanding the range of water depths and environmental conditions within which drilling operations can be safely conducted.

Azimuthing thruster units, often retractable so as to enable shallow water maneuvers, are the backbone of the dynamic positioning system. Ship-based computers and satellite-linked navigation units control the vessel's rudder, propellers, and thrusters using input from various monitoring systems, such as gyrocompass wind sensors, real-time differential global positioning systems, micro-wave positioning systems, underwater sonar

ECONOMIC BENEFITS
Minimized positioning and transit times for deepwater exploration
Reduced operating costs in deepwater exploration operations
Improved access to deepwater and ultra-deepwater resources that might otherwise have remained undeveloped

ENVIRONMENTAL BENEFITS
Less disruption to seafloor ecosystem
Reduced environmental impacts due to increased operational stability
Enhanced deepwater operational safety

beacons, and hydro-acoustic beacons. If the wind or tide swell moves the ship from its desired station, guided thrusters can automatically hold the vessel's orientation and position. They can also move it to a new position in the event of extreme weather.

A new equipment market

The trend toward long-term, ultra-deepwater exploratory operations has substantially increased demand for dynamically positioned vessels. The harsher environments of deeper offshore plays has accelerated demand for dynamically positioned drillships, semisubmersible rigs, seismic survey vessels, floating production, storage, and offloading systems, pipelayers, shuttle tankers, and standby support vessels. The benefits of dynamic positioning include:

Cost-effectiveness

When permanent or disconnectable moorings become excessively difficult or expensive, or when low-cost fuel is available, dynamically positioned systems may be highly cost-effective. Given today's technology, it would be practically impossible to conduct ultra-deepwater exploratory operations without dynamic positioning technology.

Operational flexibility

These systems allow vessels to move readily from one location to another during exploratory operations, eliminating the cost and time of setting and removing mooring lines. Such flexibility, vital during hurricane season, may ultimately reduce operating costs.

Safety

The precise positioning afforded by these systems contributes significantly to both environmental protection and worker safety during offshore operations. The safety of operations involving diving support vessels, deepwater drillships, or shuttle tankers, for instance, is often enhanced by the degree of operational precision provided by dynamic positioning systems.

The forces of wind, waves, and ocean currents cause exploration and drilling support vessels to sway, yaw, and move off course. To counter this, dynamic positioning technology stabilizes deepwater site equipment, allowing exploratory operations in waters too deep for conventional mooring systems.

METRICS

Steady drilling from dynamic positioning

Today's advanced dynamic positioning technology enables drillships to maintain station with maximum excursion levels below 1% of total water depth. At a water depth of 5,000 feet, for example, these advanced systems are able to keep a 200-yard-long, 30-story-high drillship within 50 feet of station.

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CONTACT

U.S. Department of Energy
Office of Fossil Energy
1000 Independence Avenue, SW
Washington, DC 20585

Elena S. Melchert
(202) 586-5095
elena.melchert@hq.doe.gov

Trudy A. Transtrum
(202) 586-7253
trudy.transtrum@hq.doe.gov

TECHNOLOGY Locations: Worldwide, onshore and offshore

Pneumatic Drilling

SUMMARY

Pneumatic drilling is an underbalanced drilling technique in which boreholes are drilled using air or other gases as the circulating agent. In certain cases this air drilling technique offers the promise of mudless drilling. By using nitrogen, air, or natural gas in place of oil- or water-based muds, producers can both eliminate drilling fluids that need disposal and ensure that drill cuttings are not tainted by chemicals or oil. Although it is suitable only for certain formation types and lithologies and can create potentially explosive downhole conditions—and is not therefore likely to become widespread—this technique is a very attractive environmental prospect, offering significant operational benefits.

BLUEPRINT ON TECHNOLOGY

Unlike conventional mud-based drilling, air drilling significantly reduces or eliminates drilling fluid additives and prevents formation damage

Protecting low-pressure formations and maximizing production

UNDERBALANCED drilling offers significant advantages over conventional systems in low-pressure or pressure-depleted formations. Pressure overbalances in conventional drilling can cause significant fluid filtrate invasion, and lost circulation in the formation. Expensive completions, decreased productivity, and high mud and mud-removal costs can then plague drilling operations, but these can be avoided by using underbalanced conditions. By lowering downhole pressure using a noncondensable gas in the circulating fluid system, underbalanced pneumatic drilling can prevent difficulties commonly encountered when reservoir pressures are lower than the hydrostatic pressure exerted by traditional water-based drilling fluids. Depending on the environment, gas may be used alone or with water and additives. When drilling fluid is needed for well control, gas is mixed with lightweight drilling fluids.

In general, pneumatic drilling is used in mature fields and formations with low downhole pressures, in open-hole completions, and in fluid-sensitive formations. It is an important tool in drilling horizontal wells, which must expose a large amount of reservoir face to be productive, and have minimum damage from fluids invasion. As horizontal drilling increases in popularity, underbalanced pneumatic drilling will become more widespread, because it can penetrate the reservoir without damaging the formation or its productive capacity.

Air drilling techniques to suit

Air dust drilling is a dry technique that relies on the annular velocity of air to

ECONOMIC BENEFITS

- Substantially less fluid and waste requiring disposal
- Increased rates of penetration and longer drill bit life
- Indication and evaluation of productive zones and more effective geosteering of the well by monitoring flow of produced fluids
- Potential elimination of waste pits gives access to restricted areas

ENVIRONMENTAL BENEFITS

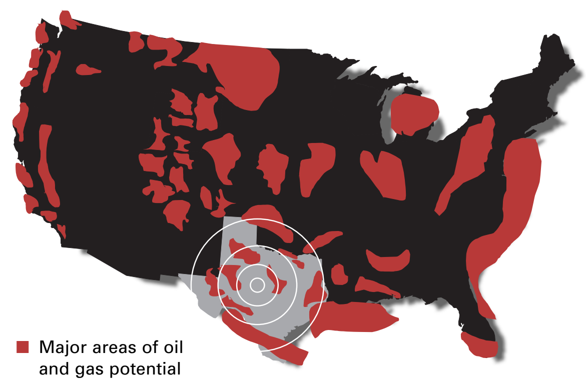
- Greatly reduced drilling fluids and chemical-tainted cuttings
- Decreased power consumption and emissions
- Better wellbore control and less damage to formations
- Fewer workover and stimulation operations needed
- Potential for smaller drilling footprints and less impact on habitats, wildlife, and cultural resources

transport cuttings. It is typically employed in drilling dry formations, or when any water influx is low enough to be adsorbed by the air stream. If excessive water influx precludes its use, *air-mist drilling* is employed instead, using an air-injected mud that returns to the surface as mist. Sometimes *foam-drilling* is required, using a stable mixture of water and compressed air with detergent and chemicals. When the water influx is too great to be removed through mist or foam, *aerated mud drilling*, a technique in which air is injected into viscosified fluid or mud in order to reduce the weight of the fluid column on the formation, combines the best properties of conventional and air drilling to provide an effective solution.

A new waste management technology enables operators to eliminate the earthen waste pits used to catch effluent created while drilling with an air- or air-mist system. Liquids and solids in the effluent are separated and treated, and gases are exhausted. By eliminating the environmental risks associated with pits, drillers can operate in otherwise restricted areas, such as State parks and within city limits. Initial field tests indicate that this technology can handle continuous liquid volumes of 90 barrels per hour and solid volumes of 14 barrels per hour.

CASE STUDIES

Success in the Field



Accessing new supplies in the Carthage field

Selected as the most viable technique to prevent damage to an extremely low-pressure reservoir, pneumatic drilling made history as the first air-drilled horizontal well in the Carthage field in Texas. Air drilling successfully increased gas recovery from depleted zones without wellbore skin damage, which would have restricted the reservoir's productive flow. Drilled in December 1995, the Pirkle 2 well had by the end of April 1997 produced 530 million cubic feet of gas at a rate of 1.1 million cubic feet per day. The well was drilled with compressed nitrogen into the Cretaceous Frost "A" zone at 6,000 feet true vertical depth; it produces through a 1,400-foot lateral well with bottomhole pressure of 185 psi. The operation successfully met the economic criteria of producer OXY USA Inc., which had determined that the well's production rate would have to at least double that of a standard vertical well to be economically viable.

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CONTACT

U.S. Department of Energy
Office of Fossil Energy
1000 Independence Avenue, SW
Washington, DC 20585

Elena S. Melchert
(202) 586-5095
elena.melchert@hq.doe.gov

Trudy A. Transtrum
(202) 586-7253
trudy.transtrum@hq.doe.gov

TECHNOLOGY Locations: Worldwide, onshore and offshore

Slimhole Drilling

SUMMARY

Improved slimhole drilling technology brings the twin advantages of environmental protection and economical results to oil and gas exploration and production. (For example, a conventional well drilled with a 12.25-inch bit and a 5-inch drill pipe becomes a slimhole when using a 4-inch bit and a 3.7-inch drill pipe.) Slimhole rigs are defined as wells in which at least 90 percent of the hole has been drilled with a bit six inches or less in diameter. Slimhole rigs not only boast a far smaller footprint and less waste generation than conventional operations, they can also reduce operating costs by up to 50 percent. The technique is proving a low-cost, efficient tool with which to explore new regions, tap undepleted zones in maturing fields, and test deeper zones in existing fields.

BLUEPRINT ON TECHNOLOGY

Technology advances in less invasive slimhole drilling increasingly valuable in exploration and production

Narrow boreholes prove highly effective

POTENTIALLY APPLICABLE to more than 70 percent of all wells drilled, slimhole drilling holds promise for improving the efficiency and costs of both exploration and production. Although the technique was first used in the oil and gas industry in the 1950s, its acceptance has been hampered until recently by concerns that smaller boreholes would limit stimulation opportunities, production rates, and multiple completions. Advances in technology, coupled with a growing record of success, have dispelled these concerns, making slimhole an increasingly attractive option for reservoir development. Today, slimhole drilling is employed throughout the lower-48 States and the Gulf of Mexico, especially in the Austin Chalk fields of South Texas. Globally, slimhole drilling has been used in a wide range of onshore and offshore settings.

As an **exploration** tool, slimhole drilling for stratigraphic testing provides geologists with a clearer picture of the local geography, refining seismic interpretation. Such testing, combined with other technologies such as continuous coring, yields valuable information for increasing success rates in exploration.

In the **production** arena, improved slimhole drilling offers a viable means of recovering additional reserves from existing reservoirs, including economically marginal fields. Resources in pay zones bypassed in the original field development can be cost-effectively accessed through the existing wellbores, thereby extending the productive life of the field.

ECONOMIC BENEFITS

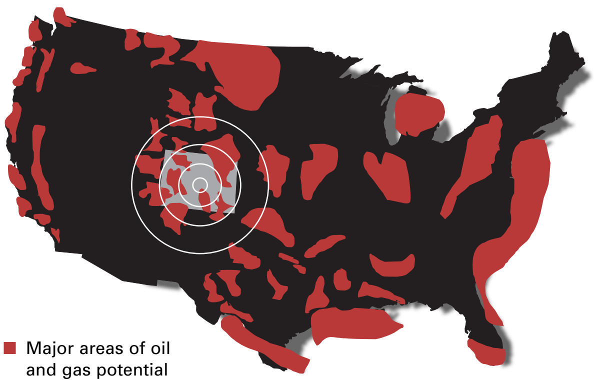
- Smaller drilling crews and less drilling time mean up to a 50 percent reduction in costs
- Slimhole drilling is critical for adding millions of barrels of oil to the Nation's reserves
- Slimhole is feasible in a wide range of operations and capable of reducing exploration and development costs around the United States

ENVIRONMENTAL BENEFITS

- A slimhole rig occupies far less space than a conventional rig—the entire footprint including site access can be up to 75 percent smaller
- The rig requires far less drilling fluid and produces far fewer cuttings for disposal
- Reduced volume and weight of equipment favors use in sensitive environments, such as rainforests and wetlands, particularly in helicopter-supported campaigns
- Better wellbore control

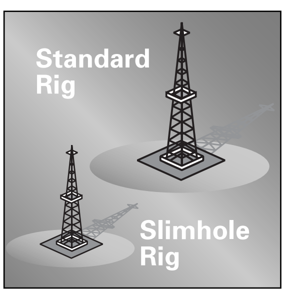
CASE STUDIES

Success in the Field



In Wattenberg field

An eight-well field test conducted by HS Resources Inc. in 1996 in the Denver-Julesburg Basin's Wattenberg field successfully demonstrated that slimhole lateral wells could be drilled from inside an existing 4.5-inch cased producing vertical well. These lateral wells with 2.375- and 2.875-inch liners are considered the first lateral cementing operations of this size liner in the Rocky Mountain region and the first reported lateral drilling in Colorado using coiled tubing. The project's success led HS Resources to begin additional slimhole drilling in 1997 and is significant for several reasons. First, this approach allows production of additional reserves with minimal impact on an active agricultural area. Second, it reduces operating costs by commingling production from both vertical and lateral wellbores.



At the Austin Chalk fields

More than 100 horizontal slimhole well reentries have been drilled by Slim Dril International, demonstrating a successful way to discover and tap otherwise inaccessible reserves of domestic oil. The company also used slimhole to deepen a conventional well to a depth of 22,000 feet, using mud motors to test a producing field. This advancing technology is extending the life of wells both at Austin Chalk in south Texas and in the Gulf of Mexico, and could potentially add millions of barrels of oil to our Nation's reserves.

METRICS

A Head-to-Head Comparison

At a drilling depth of 14,000 feet, here is how a slimhole rig with a 4-inch diameter performs versus a conventional drilling operation with an 8.5-inch diameter:

Fuel consumption	75% less
• Installed power	1,350 vs. 4,000 kilowatts
• Mud-pump power	330 vs. 3,200 horsepower
Drillsite area	75% smaller
Mud cost	80% less
• Active mud volumes	50 vs. 1,500 barrels
Rig weight	412,000 vs. 3,400,000 pounds
	150 vs. 500 helicopter lifts
	12 vs. 65 Hercules loads
	18 vs. 55 truckloads
	Drillstring weight: 37 vs. 150 tons
Drilling crew size	Staff of 3 or 4 vs. 6
Camp size	Staff of 30 vs. 80

Bottom Line:

Potential well cost-savings of 50%

Source: Nabors Industries

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CONTACT

U.S. Department of Energy
Office of Fossil Energy
1000 Independence Avenue, SW
Washington, DC 20585

Elena S. Melchert
(202) 586-5095
elena.melchert@hq.doe.gov

Trudy A. Transtrum
(202) 586-7253
trudy.transtrum@hq.doe.gov

TECHNOLOGY Locations: Worldwide, deepwater

Synthetic Drilling Muds

SUMMARY

Drilling fluids are essential to carry cuttings to the surface, maintain pressure balance and stability in the borehole, lubricate and clear the drillstring and bit, and prevent the influx of other fluids. Today's advanced offshore drilling practices include the use of synthetic-based muds (SBMs), which combine the higher performance of oil-based muds (OBMs) and the lower toxicity of water-based muds (WBMs). SBMs are a high-performance, environmentally friendly choice for complex offshore drilling environments. Management of fluids and cutting wastes is a significant responsibility for the industry, and in remote offshore areas can entail significant expense. Compared with OBMs, drill cuttings from SBMs can be safely discharged in many offshore areas, significantly reducing disposal costs and environmental impacts.

BLUEPRINT ON TECHNOLOGY

New synthetic drilling muds combine the performance of oil-based muds with the easier, safer disposal of water-based muds

Conventional versus new muds

Nearly all wells less than 10,000 feet and 85 percent of deeper wells are drilled with water-based muds (WBMs), making them the most commonly used muds both onshore and offshore. With a 90 percent water base, WBMs and associated cuttings can typically be discharged on-site. However, they are often not technically feasible or cost-effective in complex drilling situations. As such, oil-based muds (OBMs) are often the drilling fluids of choice in deep, extended-reach, high-angle, high-temperature, and other special drilling environments, greatly outperforming WBMs. But their diesel or mineral oil base means that although they effectively minimize drilling problems, OBMs cannot be discharged on-site. At remote offshore sites, operators must incur the expense, logistical problems, and environmental risks of shipping OBM wastes back to shore for disposal.

The development of synthetic-based muds (SBMs) was driven by industry's need for a drilling fluid with lower

ECONOMIC BENEFITS
Improved drilling speeds, lower operating costs, and shorter completion times (versus WBMs)
Reduced downtime from common drilling problems (versus WBMs)
Minimal to no waste hauling and disposal costs (versus OBMs)
Reduced drilling costs as SBMs can be reconditioned and revised (versus WBMs)
Increased access to resources by high-angle, extended-reach, and horizontal wells (versus WBMs)

ENVIRONMENTAL BENEFITS
Lower concentration of inherent contaminants, such as complex hydrocarbons (versus OBMs)
Safe discharge of drill cuttings (versus OBMs)
Less waste than WBMs, as SBMs are reusable
Faster drilling, so reduced power use and air emissions (versus WBMs)
Smaller footprint, as SBMs facilitate extended-reach and horizontal wells (versus WBMs)
Increased worker health and safety—volume and toxicity of irritating vapors lower than OBMs
Reduced air pollution because SBMs are not transported to shore for disposal (versus OBMs)
Reduced landfill usage
Increased wellbore control (versus WBMs)

disposal costs than OBMs and higher levels of performance than WBMs. In general, SBM performance is comparable to that of OBMs, and in some cases superior. They are manufactured by chemical synthesis from basic building blocks of relatively pure materials, forming highly uniform products. By varying the components and manufacturing conditions, different SBMs can be created that exhibit varying rheological properties and environmental performance parameters. Current synthetic fluids fall into several groups: polyalphaolefins (PAOs), linear alpha olefins (LAOs), internal olefins (IOs), fatty acid esters, and others.

Comparing costs
Although more expensive on a per-barrel basis, SBMs can reduce overall drilling expenses. When measured against WBMs, SBMs can shorten drilling time. Compared with OBMs, SBMs offer lower disposal costs.

METRICS

Advantages of synthetic muds as demonstrated by Marathon Oil in the Gulf of Mexico

Footage Drilled	Footage per Day	Mud Cost in $ Millions	Cost $ per Foot	Total Well Cost in $ Millions	Total Days
WBM Wells					
17,981	138	1.3	74	11.6	163
16,928	63	2.5	150	18.3	326
17,540	82	–	–	9.6	214
17,142	101	1.6	90.4	12.7	197
17,381	215	–	–	10.1	77
SBM Wells					
16,842	301	0.8	48	5.0	50
18,122	275	1.7	94	7.8	75
17,250	431	0.8	45	3.7	33

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CASE STUDIES

Success in the Field

Proof in the Gulf
A set of Gulf of Mexico wells with similar characteristics were the scene for a comparative study of the relative merits of SBMs and WBMs. Marathon Oil drilled five wells with WBMs and three with SBMs, and found that SBM performs with greater overall efficiency. For example, the SBM wells averaged 336 feet per day and 53 days per well, compared to 120 feet per day and 195 days per WBM well. Despite higher per-barrel costs, SBM resulted in lower total drilling mud costs and downtime costs. Overall, total drilling and completion costs for the SBM wells were in the range of $3.7 to $7.9 million per well, compared with $9.6 to $18.3 million for WBM wells. Combined with significant increases in productivity and decreased environmental impacts, these results proved that SBM was the better performer for these wells.

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CONTACT

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Washington, DC 20585

Elena S. Melchert
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