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E&P: An Investor's Guide

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A supplement to

Oil and Gas Investor

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THE UPSTREAM LEARNING CURVE

The oil and gas exploration and production (E&P) industry is dynamic, changing daily, and not just because of fluctuations that occur nearly every second in oil and gas prices.

Instead, each day, members of the industry develop a less-expensive way to find myriad types of oil and gas in many myriad more types of traps and faults and other structures, in diverse conditions from the freezing North Slope and Siberia to the equatorial basins of South America, Africa, the Indian Ocean and southern Asia.

The industry also regularly finds a more efficient way to extract this oil and gas, a more suitable way to finance each endeavor, and imaginative ways of hedging all of this risk.

Each day, what is important to and worries each E&P company can change. Today, a producer may be aiming to diversify his assets from wholly offshore to some onshore; two years from now, the company's debt-to-equity ratio may be foremost in mind; two years ago, it may have been whether that year's roster of high-risk drilling prospects would show oil and/or gas.

When an E&P executive has the rare opportunity to look ahead at the company's future and feel confident that all the oil and gas will surface and all the dollars will come in, this is exactly when he worries yet more. It is surely just the calm before the storm.

This conservative attitude among what are otherwise wildcatters is because during the past 150 years or so of the hydrocarbon age, there have been many storms and almost all of them have left some or many producers out of time and out of money.

These storms have mostly been boom-to-bust price cycles. What goes up does eventually come down. Where will that particular producer be in the balance sheet when prices come down? And, before prices find bottom? That's what each producer fears.

Other storms are unique to particular producers. Some use natural gas in lifting oil, for example. At one time, gas prices were less than $1 per thousand cubic feet. In the past few years, they have been better than $4 per thousand. A producer who uses natural gas to extract oil may have to consider suspending operations. Or, he may begin to simply sell the gas he is producing, instead.

The industry faces huge obstacles—apparent impasses that would break other types of business, crush them into obsolescence. Yet, each hurdle is overcome, if not in time to bring the project to production today, then eventually. For example, long-known oil and gas reserves are being brought to the surface now with the use of the steam-assisted, gravity-drainage (SAGD) technique that wouldn't be economic at lower oil prices.

Elsewhere, thousands of coalbed-methane wells have been drilled and completed, each making possibly as little as 10,000 cubic feet of gas per day. In a $2 natural gas market, the gas from these wells is worth about $20 a day. Why bother? In today's market, the gas is worth about $120 a day. Over a year, that's $43,800 per well, each well may have cost $100,000 or less to drill and complete, and the company has 1,000 of these. And, the average well's life is 20 years. Suddenly, this small amount of gas is worthwhile.

In all of this, investors are the key to a thriving E&P industry. The risks can at times be high, but they have been known to at times be incredibly rewarding too. A hundred shares of Devon Energy Corp. in 1993 cost about $400; today, they're worth about $6,000—a 1,400% return.

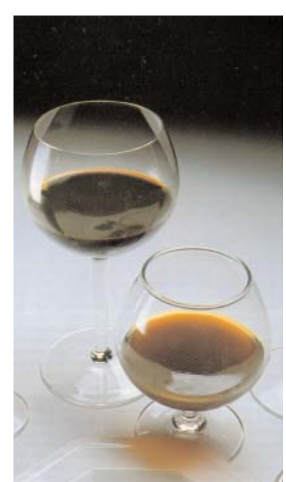
Newcomers to the industry are usually amazed—and sometimes overwhelmed—by the jargon, by the technology, by the peculiarities, by the logistics, by the size of this massive energy business. This special report was prepared for those just getting started, and for those wanting to brush up on some basics.

Newcomers need not be overwhelmed. Industry veterans will gladly admit that they learn something new about the business every day too—and should! It's a dynamic, ever-changing industry. When there's nothing more to learn about this business, there's probably nothing new happening in it—no innovation, no great new discoveries, no new risk-management tools, no new sources of capital, no new players—like you.

Welcome to the E&P business.

—Nissa Darbonne,
Executive Editor

E&P: An Investor's Guide



ABOUT THE COVER: Illustration by Mark Shaver.

IN PURSUIT OF PETROLEUM

The hunt for oil and natural gas uses tried-and-true principles of petroleum accumulation combined with the latest state-of-the-art tools.

Back in the earliest days of oil exploration, people looked for petroleum by drilling along creeks, on top of oil seeps, and on surface domes and structures. Most times, luck was more of a factor in their success than skill.

The science of petroleum exploration developed along with the industry. Today, the easy oil and gas has already been found, and the hunt for hydrocarbons is an extremely sophisticated, highly technical effort.

Oil and gas are now sought in many remote locations around the globe: in water more than 10,000 feet deep in the Gulf of Mexico, the deserts of Egypt and China, the mountainous western Canada and Colombia, the islands of Indonesia, and the swamps along the coasts of Louisiana and Nigeria's Niger Delta.

Nevertheless, the fundamentals of geology remain unchanged. Oil and gas are found in sedimentary rocks, which cover about 75% of the earth's land area. About 700 sedimentary basins dot the world; about half of these have been explored for oil and gas. Limestones, dolomites, sandstones, shales and siltstones are the hunting grounds for petroleum geologists.

It is within these layered rocks that the explorer searches for the four elements necessary for a petroleum accumulation: source, reservoir, trap and seal. Petroleum source rocks are often thick, black marine shales laid down in ancient seas. As soon as a plant or animal dies, bacteria attack its remains. If oxygen is plentiful, as in soil, bacteria will consume all the organic matter.

But in very fine-grained muds deposited on the sea floor, oxygen is limited and much of the organic matter escapes destruction. As these muds are buried by successive layers of sediment, rising heat "cooks" the organic matter, throwing off water, carbon dioxide and hydrocarbons.

Generating crude oil from organic matter in source rocks is a slow process, requiring millions of years. Temperatures must be just perfect—oil can only be formed between 120 and 350 degrees Fahrenheit, temperatures found at burial depths between 5,000 and 21,000 feet. If the source rocks get any hotter, natural gas and graphite are formed instead.

Reservoir rocks are hosts for hydrocarbons.

Remote monitoring in an Input/Output Inc. recording truck of results from a seismic survey in Rulison Field in Colorado's Piceance Basin.

Steps In The Life Of A Prospect

1. Acquire seismic, surface and subsurface data (well logs, cores and tests) in area of interest.
2. Generate prospect idea.
3. Acquire leases through purchase or farm-in arrangement.
4. Estimate drilling and completion costs to test prospect.
5. Predict expected volume of reserves, likely production rates and operating costs.
6. Run a model of economics to determine the rate of return, cash flow and expected value generated by the sale of the oil and gas if the prospect is successful.
7. Assess stratigraphic and structural risks and determine if the expected returns are sufficient to justify the capital expenditures.
8. Apply for federal and/or state drilling permits.
9. Contract drilling rig, mud-logger, cementing and well logging services.
10. Prepare location and move in rig.

Much the opposite of good source rocks, reservoir rocks have porosity and permeability and are deposited in environments of considerable energy. High-energy environments such as waves and currents remove mud particles and most of the organic matter, leaving the pores open. Reservoir-quality sandstones and limestones usually contain very little organic matter; oil and gas migrate into reservoirs after they have been generated.

Movement of oil and gas from source rocks into reservoirs is called primary migration. Oftentimes, reservoirs are full of oil that has moved just a short distance from surrounding shales. But, huge oil accumulations also exist in areas that are hundreds of miles from the original source rocks.

Once crude oil and natural gas have formed, they continually seek lower pressures, moving through natural conduits in the earth's layers. If no barriers intercede, hydrocarbons will eventually seep out on the surface.

What often occurs, however, is that migrating oil and gas hits a sealing layer beyond which it cannot pass. Seals are sedimentary rocks with negligible permeabilities that do not allow oil and gas to migrate any farther upward. Thick salt layers provide excellent seals, as do shales.

Oil and gas are now contained in a trap. Folded or faulted rock layers can form structural traps, which are commonly anticlines, domes or horst blocks. Stratigraphic traps form as a result of changes within the rock layers, as when porous rocks such as reefs or river-channel sandstones are surrounded by nonporous rock. Combination traps, with both structural and stratigraphic elements, are also possibilities.

Once in a trap, gas, oil and water separate by

One of the most tried-and-true axioms of petroleum exploration is that the best place to look for oil and gas is near where it's already been found.

AN EXPLORATION GLOSSARY

Anticline A fold, generally convex upwards, whose core contains stratigraphically older rocks.

Core data A solid column of rock up to four inches in diameter taken from the wellbore so geologists may study the rock formation for clues as to whether oil or gas is present.

Drillstem test A test of the productive capacity of an oil or gas reservoir when the well is uncased. The test is conducted through the drill pipe to see if oil or gas is present in a certain formation; preliminary sampling aids the decision to complete or abandon the well.

Fault A fracture or fracture zone along which the sides have been displaced relative to one another. A break or fracture in the Earth's crust that causes rock layers to shift.

Field An area in which a number of wells produce from a reservoir. There may be several reservoirs at various depths in a single field.

Horst An elongate, uplifted block that is bounded by faults on its long sides.

Hydrocarbon An organic compound consisting of carbon and hydrogen. Hydrocarbons can be gaseous, liquid or solid.

Log A continuous record as a function of depth of information on the rocks and fluids encountered in a wellbore. The readings are commonly obtained by equipment lowered by wireline into the wellbore. Acoustic, radioactive and electrical readings are used to identify the types of rocks and their characteristics. Measurement-while-drilling (MWD) tools can accumulate data as the drill bit drills through the rock formation.

Permeability The capacity of a rock to transmit fluids. A tight rock, sand or formation will have low permeability and thus, low capacity to produce oil or gas, unless the well can be somehow fracture-stimulated to increase production.

Expressed in millidarcies for tight reservoirs and darcies for extremely permeable reservoirs.

Porosity The volume of small to minute openings in a rock that allow it to hold fluids. Measured in percentages, typically from near zero to about 35%.

Prospect An area that is the potential site of an oil or gas accumulation. A lease or group of leases upon which an operator intends to drill.

Reserves The volumes of oil and gas that can be profitably recovered from a well with existing technology and present economic conditions.

Sedimentary rock A layered rock resulting from the consolidation of sediment. Sediments are materials that are transported and deposited by wind, water or ice, chemically precipitated from solution or deposited by organisms.

Seismic An earthquake or earth vibration, including those that are artificially induced.

Strike The direction taken by a structural surface such as a bedding or fault plane.

Wellbore That part of a well that is below the surface. Hole diameters vary with the type and purpose of wells; a common wellbore diameter is a little less than nine inches.

(Source: *Dictionary of Geological Terms*, Third Edition) density, with gas rising to the cap position, oil in the middle and water occupying the bottom. The boundary between gas and oil is called the gas-oil contact; the boundary between oil and water is the oil-water contact.

Petroleum exploration tools

Maps have always been key tools of petroleum exploration. Since the early 1900s, explorers have found many oil and gas fields by drilling domes and anticlines that could be identified from surface mapping. The size, position, dips and strikes of surface beds are all recorded with instruments such as plane tables and Brunton compasses. Today, the map of an explorer includes this "traditional" information, as well as that gleaned from aerial photographs and satellite pictures.

Early geologists made common use of sample and drilling information from wells. As technology advanced, well log data and core data added a great deal of knowledge.

Today, information from such instruments as formation sampling tools can assist in the evaluation of both rocks and fluids in a wellbore. Among wireline tools that provide valuable insights into the subsurface are electric, radioactive and acoustic logs, as well as dipmeters, borehole imaging logs and magnetic resonance imaging logs. Data from drillstem tests are also incorporated into a subsurface picture. Even geochemical techniques, which seek to correlate surface measurements of various chemical compounds with the underground occurrence of hydrocarbons, are sometimes called into play.

Geophysicists also bring some tremendous tools to the trade of petroleum exploration. Three common geophysical methods used to look for oil are magnetic, gravity and seismic exploration. Magnetic methods measure the strength of the Earth's magnetic field at a specific point on the surface, while gravity techniques seek to determine the strength of the Earth's gravity at a location. Both methods are useful in reconnaissance mapping and are usually employed in the early stages of basin evaluation.

Seismic is the real workhorse of the industry, however. In seismic prospecting, acoustic sources such as dynamite, vibrations or sonic impulses from compressed air transmit sound into the ground. As acoustic signals pass into the subsurface, they are reflected and refracted off the various sedimentary layers. Signals that bounce back to the surface are recorded and processed to form an image of the subsurface.

Two-dimensional (2-D) seismic yields a cross-sectional view of the subsurface in two planes, length and height, while a 3-D survey delivers a complete volume of data that allows the explorer to image the subsurface in fine detail. A further enhancement is 4-D seismic, which adds the dimension of time to the geophysical process. In this technique, successive

Seismic-survey trucks travel across Rulison Field in Colorado, using shear-wave and conventional p-wave vibrators. Seismic data is the workhorse of the exploration industry.

STRANDED ENERGY

There are many areas of the world in which oil and gas have been found or are suspected to exist, but have not been explored or brought into production. This is more common with known gas accumulations, and the reason is that the gas is in a remote area where there is little or no indigenous demand for the product, and moving the gas—via a liquefied natural gas (LNG) tanker or a very long pipeline—to a location where there is a market would be too costly and financially risky. These gas accumulations are commonly called "stranded gas."

Another reason, and this can include areas of known oil accumulations, may be that the area is off-limits to exploration and production. There are many areas of the U.S., including Alaska, that fall into this category.

WHOSE FAULT IS IT?

Often, in spite of computers chock full of seismic data, months or years of study, and countless pre-drill technical reviews by hordes of geoscientists and managers, wells still come up dry. A dry hole can be defined as a well that does not produce oil or gas in commercial quantities.

There are relative degrees of dry holes, or dusters as they are often called. A hole can lack so much as a whiff of oil or gas, with no hydrocarbon shows detected by even the most sensitive gas chromatographs. Or, a well can be a near miss, with not quite enough ability to produce petroleum to make the economic cut.

These latter types of dry holes are often revisited in times of high oil and gas prices. Too, dry holes that were noncommercial years ago can sometimes be re-entered and made into producing wells, thanks to advances in completion technology.

Failures can stem from many factors:

1. Mechanical problems can force a company to abandon a well. Drillpipe or drilling tools can get stuck in the hole, and sometimes the well must be abandoned.

2. A hydrocarbon-bearing reservoir isn't present in the wellbore—even though it may be a few feet away. Reservoirs can be faulted out by small structural displacements in the subsurface that can't be detected with seismic data.

And, rocks can change laterally; for example, a sandstone can grade into a shale interval.

3. The target reservoir is encountered, but the interval is too tight or too thin to produce economic quantities, or contains water instead of hydrocarbons.

4. A well drilled on a seismic anomaly finds conditions that are indeed anomalous, but that do not correlate to a productive reservoir. For instance, an anomaly may look like a gas-charged sandstone on seismic data, but drilling reveals it is actually a thin, tight limestone layer.

5. The reservoir is found at a depth that is lower than projections. Many assumptions about the acoustic velocity of the rock layers in an area are built into seismic interpretations, and until wells are actually drilled estimates can be imprecise. Low wells are usually wet.

6. A well intersects the reservoir at the anticipated depth, and has adequate porosity and permeability, but the hydrocarbons have leaked off because the seal wasn't adequate. Or, trap, reservoir and seal are all found as predicted, but oil and gas never migrated into the area in the first place.

Facing page, rig hands change the bales on the top drive of a rig while drilling the #1-H Dunlavey in the Barnett Shale in Johnson County, Texas.

3-D surveys are acquired over an area to track the movements of fluids in the subsurface.

Traditional seismic relies on the information carried in compressional waves, but an emerging approach extracts subsurface information carried in shear waves. This type of seismic, called multi-component or full-wave seismic, is very good at imaging stratigraphic reservoirs and fractured reservoirs.

Where shall we drill?

Nonetheless, piles of highly processed seismic data, satellite images, high-tech well logs and computer-aided mapping programs can't create oil or gas where none exists. The explorer still must hunt for some basic clues.

One of the most tried-and-true axioms of petroleum exploration is that the best place to look for oil and gas is near where it's already been found. Working in a known hydrocarbon basin eliminates many of the uncertainties of source, reservoir and seal, and the hunt can focus on location of possible traps.

The first phase of exploration is a search for traps similar to those that are already producing. Explorers are also ever alert for possibilities of new trap types that have not yet been known to produce in an area, such as updip pinchouts of permeability or fault traps.

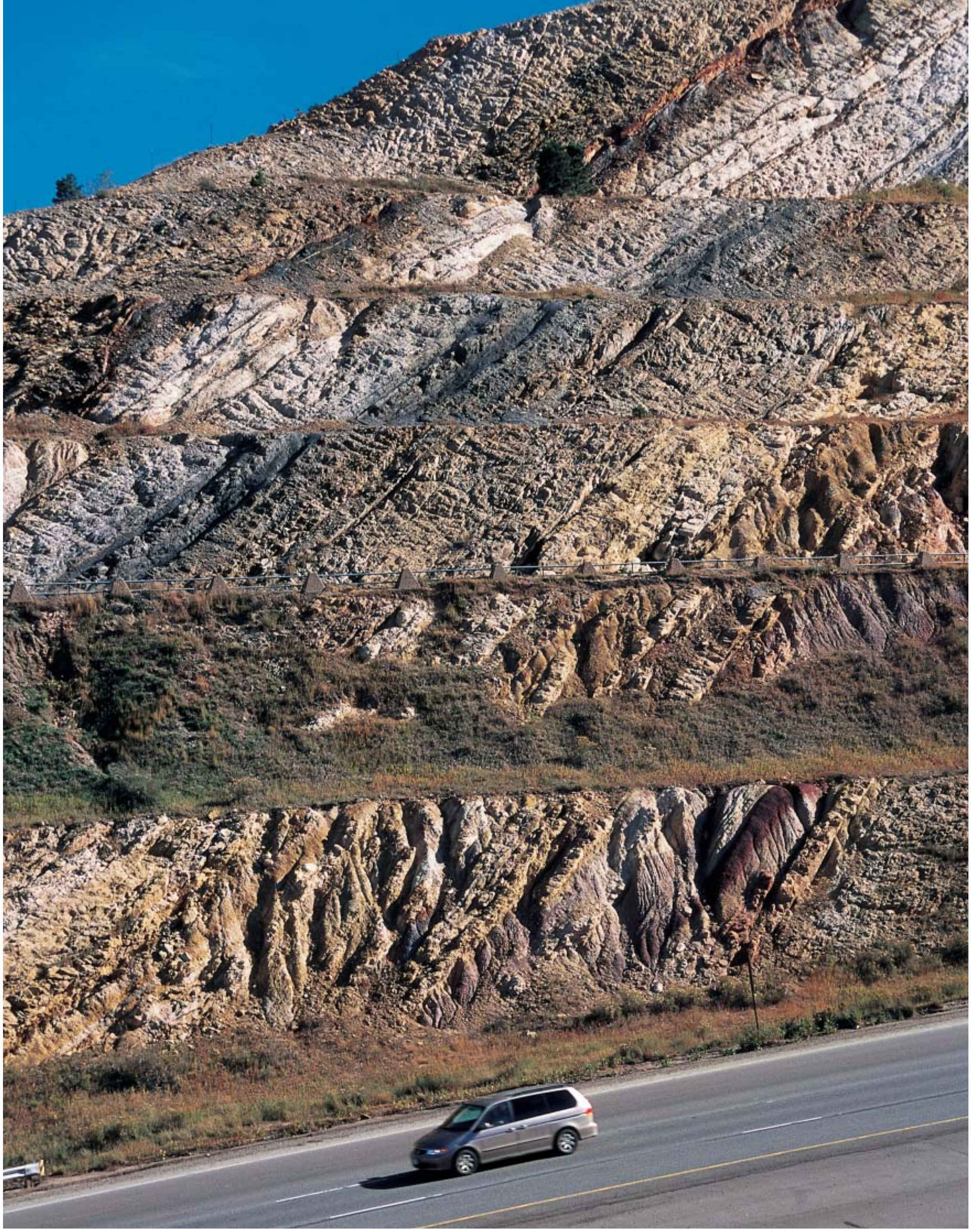
Oil and gas "shows" in previously drilled wells nearby are of supreme importance, because they are direct indications that a trap exists. Other important clues include changes in the rate of dip, dip reversal or flattening of dip of the rock layers. The location and position of faults is another key. These can indicate an unusual structural condition.

Seismic attributes offer other clues. Amplitudes of seismic signals contain tremendous geological detail, and much effort is invested in interpreting these subtleties. One seismic signature may show a promising gas-charged sand; another may indicate a tight limestone bed with no commercial potential.

Geologists and geophysicists formerly worked with pencils and paper maps and sections; today they build complex, 3-D interpretations on their desktop workstations. The fundamentals of prospecting remain unchanged, but phenomenal strides have been made in an individual's ability to view and integrate data from many sources.

The decision to drill

If, after carefully weighing all the data—and being fully aware of its varying degrees of reliability—an explorer still believes that an undrilled trap does exist, a prospect has been born.



Sometimes, the geology of the subsurface is apparent from road cuts. This cut is through the Dakota Hogback west of Denver. The Dakota sandstones are prolific oil and gas reservoirs.

The land situation, productive possibilities and expected costs must be considered to mature the idea. Lots of great prospects are never drilled because the company couldn't tie up the acreage through leasing the mineral rights. Other ideas are discarded because the potential reserves are judged insufficient in light of a prospect's risks and drilling expenses.

Some prospects that were once thought to be viable become impossible and must be deferred or canceled if oil and gas prices fall lower than the original assumptions. A prospect is a labor of many months or even years. Companies typically have many internal screenings to evaluate prospects. They consider the risks of the geological and geophysical factors; estimate possible reserves and production rates; design the drilling and completion programs; and estimate the operating costs, royalty and tax burdens, and arrive at estimated cash flow.

Prospects are ranked against other opportunities available to the company, such as drilling in other U.S. basins or other countries, or acquiring reserves or acreage from another company. And, they are reexamined as oil and gas prices, company budgets and capital sources fluctuate.

If the decision to drill is made, federal and/or state drilling permits are secured and a drilling rig is hired. The abstract idea will finally be tested with money and with iron. In the end, Mother Nature will have the last word, despite all the high-tech equipment, intellectual effort, and land and seismic expenses that have been invested by the prospector.

—Peggy Williams

UNCONVENTIONAL GAS

Natural gas is increasingly being categorized today as conventional and unconventional. What's the difference?

It's no secret to anyone in the oil and gas industry that the low-hanging fruit in the Lower 48 has been picked. Conventional plays have been waning for some time, making resources harder to find and more costly to produce.

According to the U.S. Department of Energy's Energy Information Administration (EIA), technological improvements and rising natural gas prices will cause production from unconventional gas resources—coalbed methane, tight gas sands and shales—to increase faster than conventional gas production.

In its "Annual Energy Outlook 2005," the EIA estimates that Lower 48 unconventional production will grow from 6.6 trillion cubic feet (Tcf) in 2003 to 8.6 Tcf in 2025 and will account for 44% of Lower 48 gas production in 2025. Currently, unconventional gas accounts for nearly one-quarter of total domestic supply.

The growth potential of unconventional reserves is even more dramatic when looked at on a regional basis. David Morrison, chairman of Edinburgh-based research firm Wood Mackenzie, has said that by 2020, Rockies production could be 90% unconventional and 10% conventional.

The DOE is reading its own unconventional tea leaves and in October 2005 announced $10.7 million in funding for 13 research and development projects focusing on recovering large, unconventional gas and oil resources and improving the environmental aspects of drilling for gas and oil.

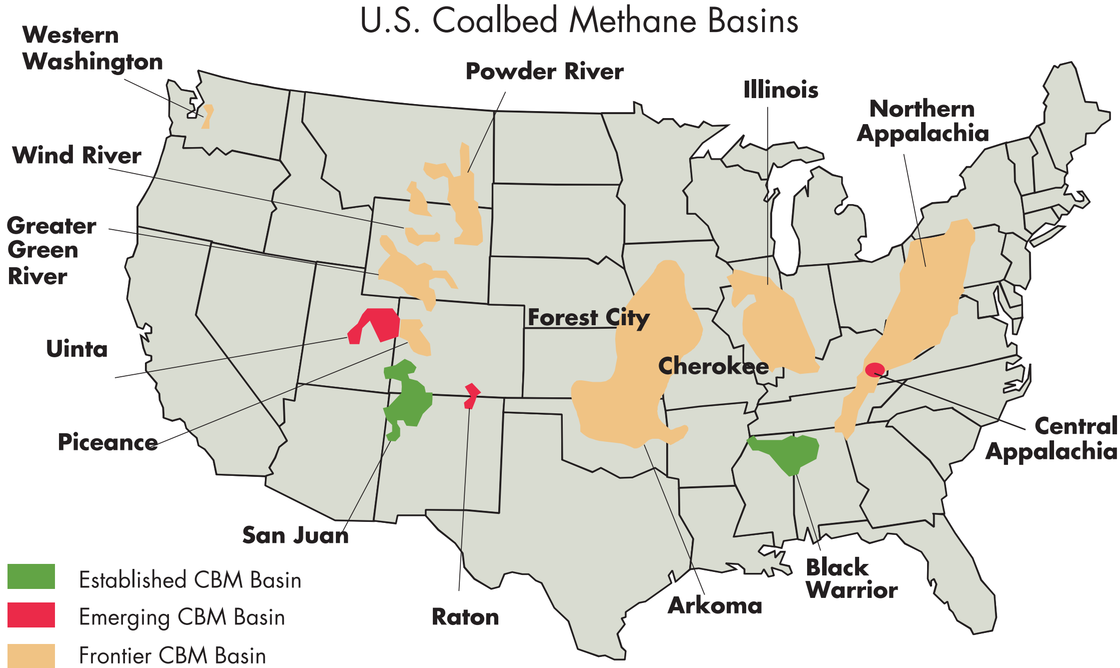
Coalbed methane

Methane trapped in coal seams and contained within the coal itself is an explosion hazard to mining operations. But what used to be a scourge has become a valuable energy commodity as gas prices climb and coalbed-methane (CBM) extraction technologies advance.

According to the EIA, coalbed gas is becoming a mature source that in 2004 accounted for 9% of U.S. dry gas production. Production in-

Coalbed methane has become a valuable energy commodity as gas prices climb and extraction technologies advance.

U.S. Coalbed Methane Basins



Source: Advanced Resources International

Special, graded sand is used in fracturing wells, which has the effect of stimulating gas flow. Facing page, water displacement is used to measure gas released from coal and shale samples.

creased in 2004, but proved coalbed gas reserves declined 2% to nearly 18.4 Tcf. (The last decline was 10 years earlier in 1994.) Still, it accounted for nearly 10% of 2004 U.S. dry gas proved reserves. CBM is the fastest growing of all the unconventional gas categories.

Gas can reside in a coal seam in two fashions. It is absorbed into the coal, and it also occupies porous space within the coal seam, in fractures and cleats. Operators extract core samples from coal seams to arrive at estimates of gas content, as well as an understanding of how gas is contained within the seam.

In order for gas to be desorbed from the coal in which it resides, operators usually must remove vast quantities of water from the reservoir, depressurizing it and allowing the gas to escape from the coal. "It may be days, weeks, even months and a lot of water that you need to produce prior to seeing any gas production," explains Kent Perry, director of exploration and production research at the Gas Technology Institute (GTI).

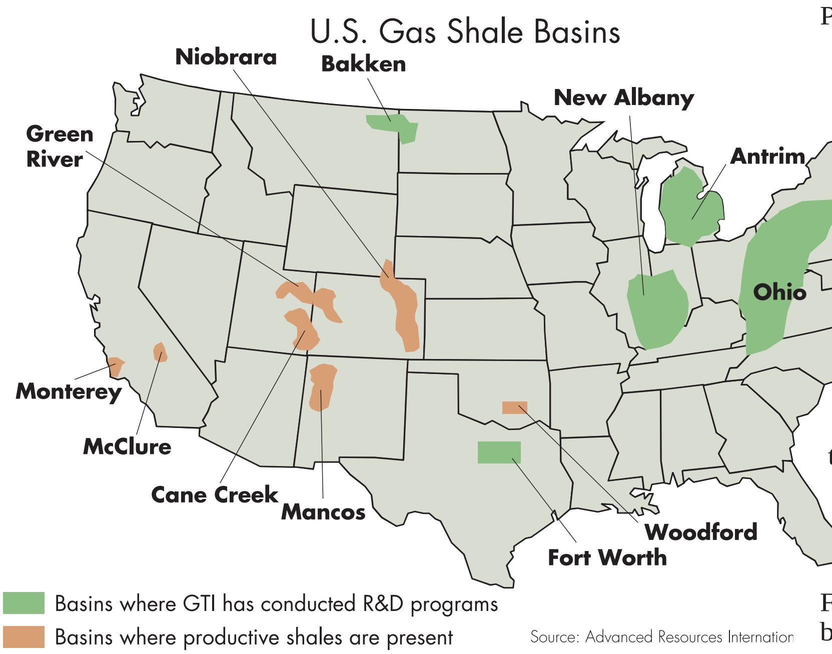
The dewatering process is complicated significantly by the fact that operators must find a place to put the produced water. Water disposal on land would not be an option for environmental reasons if the water is salty. Sometimes the produced water can be treated to make it acceptable. Other times producers opt to drill water-injection wells and dispose of the water by re-injecting it. Whatever strategy is chosen for handling produced water, it's important to consider the associated costs in project economics.

Shale-gas production has traditionally been associated with Devonian-age Ohio shale, but other basins produce significant quantities of shale gas.

Shales

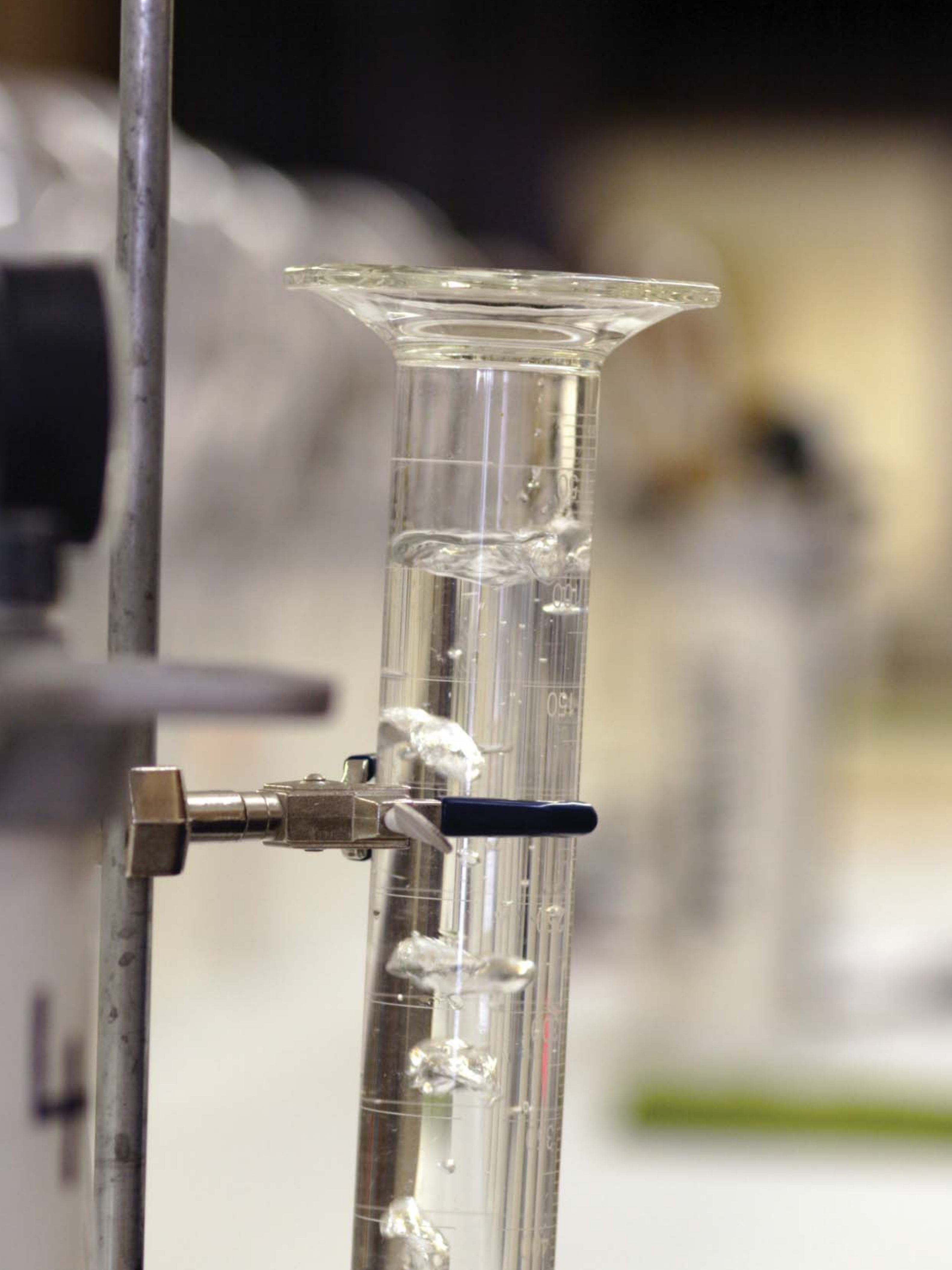
Shale is a very fine-grained sedimentary rock, easily breakable into thin, parallel layers. The rock is very soft but does not dissolve in water. Shales often hold gas when two thick shale deposits sandwich a thinner area of shale. Fractured shales produce about 500 billion cubic feet (Bcf) of gas per year in the U.S. The Mississippian Barnett Shale in the Fort Worth Basin of North Texas is the leading fractured-shale play in North America.

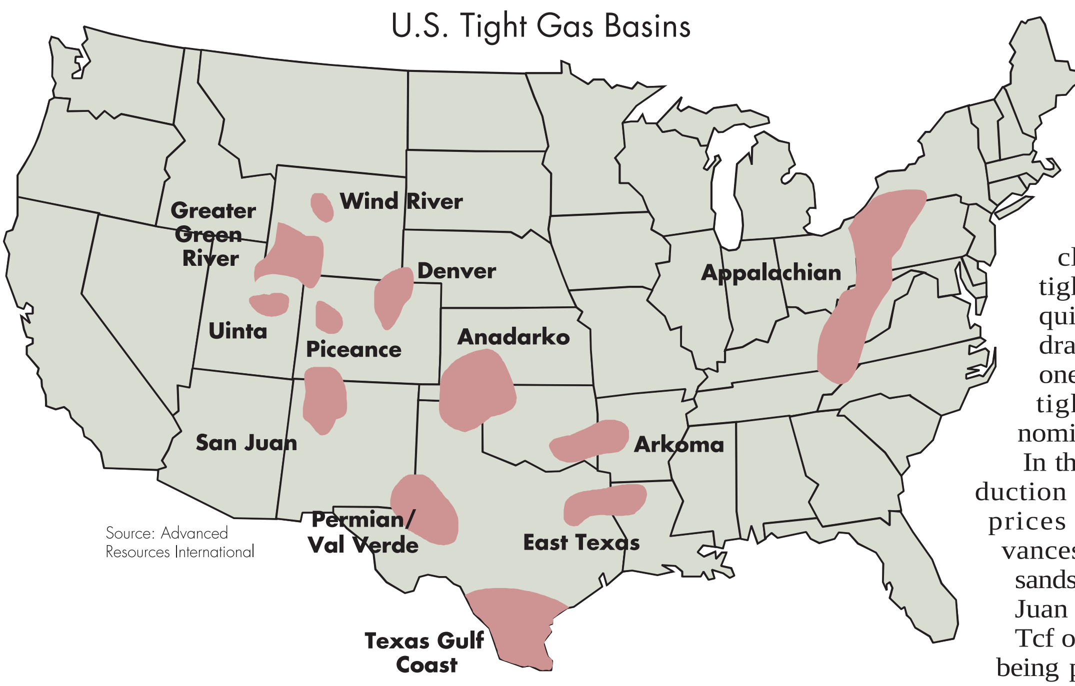
Fractured shales have been a gas source since the early days of the U.S. gas industry. The first known U.S. gas production came from a fractured shale reservoir in the Appalachian Basin. Production has traditionally been associated with Devonian-age Ohio shale, but other basins produce significant quantities of shale gas.



The Gas Technology Institute has researched gas production from shale basins for about 15 years and has evaluated formations in Ohio, Illinois and Texas, as well as focusing on the Antrim Shales in Michigan. The properties of shale also make relevant GTI's other research on tight gas sands fracturing and CBM. Through studying 2,000 wells in Michigan, GTI found that production rates from shale could be doubled through the use of such techniques as two-stage, deeper hydraulic fracturing.

In 2001, more than 28,000 shale wells were producing nearly 380 Bcf per year from the Appalachian, Michigan, Illinois, Forth Worth and San Juan basins. The New Albany Shale and other Devonian shales are gar-





A high level of tight-gas drilling is expected in most of the major basins for several years, and substantial new growth is anticipated in the Rockies.

nering renewed interest. There is as much as 1.9 Tcf of technically recoverable reserves estimated in the New Albany, and several companies are consolidating large lease blocks or obtaining permits to produce gas from the play, according to a late 2005 report by the Appalachian and Illinois Basin Directors of the Interstate Oil and Gas Compact Commission.

"One barrier to New Albany gas production lies in the shortage of infrastructure for gathering, compression, and processing to move the resources to market through the interstate gas transmission network," the report says.

Texas' Barnett Shale is an extremely hot play as output has jumped five-fold since 2000. Devon Energy is responsible for roughly half of the play's total production of 1.1 Bcf per day. Mitchell Energy, which was acquired by Devon in 2002, is credited with making the Barnett play viable through the development of appropriate drilling and completion techniques.

Likewise, in the Fayetteville Shale of north-central Arkansas, activity also is picking up. Arkansas produces about 180 Bcf of gas per year. But some think that could increase as much as 20% when production from the Fayetteville Shale ramps up in 2006. If the predictions of some experts are met, increased production from the Fayetteville Shale could make Arkansas a net exporter of gas once again.

Tight gas sands

Tight gas sands, which account for about 19% of U.S. gas production, are characterized by low permeability. They are by far the most prolific of the unconventional gas sources. Gas is trapped in very tight formations, usually impermeable hard rock, sandstone or limestone. Hence, production of gas from tight sands depends greatly on successful fracturing of the rock.

Tight gas sands reservoirs also are widely dispersed. Because economics dictate wellbore positioning close to the gas resource, tight gas reservoirs can require thousands of wells to drain. Horizontal drilling is one technique that can make tight gas sands more economic.

In the past, tight gas sand production was driven by high gas prices and technological advances. Production from these sands first developed in the San Juan Basin. By 1970, about 1 Tcf of gas from tight sands was being produced per year. Basins that tend to dominate in terms of tight production activity are South Texas, East Texas, San Juan, Permian and Wyoming's Green River Basin. Others include Wind River, Uinta, Piceance, Denver, Raton, Anadarko, Arkoma, Arkla, the Texas Gulf Coast and Appalachian.

A high level of drilling is expected in most of the major basins for several years, and substantial new growth is anticipated in the Rocky Mountain basins because of the large volume of gas in place. The National Petroleum Council has done studies that estimate 230 Tcf of total U.S. reserves remain to be discovered in new fields, largely dependent on technological advances. Of the 230 Tcf, about 58% is in the Rocky Mountain basins.

Of the DOE funding for unconventional resources R&D announced in October, nearly $1 million will go to researchers at the University of Texas at Austin to enhance 3-D hydraulic fracture models. The enhanced model will be tested by designing and executing hydraulic fracture treatments in tight gas sands. Tight gas operators are now benefiting from real-time, near-bit sensors that allow alteration of the drilling target based on new reservoir information.

Anadarko Petroleum Corp. is one operator that has pursued tight gas. It operates in northern Louisiana's Vernon Field and in the Bossier Play in East Texas. Anadarko sometimes fracs the same wellbore in five or six stages to achieve production. In many tight-gas basins, multistage fracturing is becoming the norm.

In the Texas Panhandle, the tight-sand Granite Wash play has expanded to cover hundreds of square miles. Higher gas prices, improved completion technologies and recent downspacing orders by the Texas Railroad Commission have caused a surge in drilling activity in Granite Wash.

—Joe Fisher

DRILLING ECONOMICS

Virtually every oilfield decision is founded on profitability. With no control of oil and gas prices, and facing steadily rising costs and declining reserves, companies' basic decisions are based on constantly moving targets.

Make no mistake, drilling, completing and producing oil and gas wells is an extremely complex business. One might think that the world's unslakable thirst for cheap, abundant energy resources makes profitability a sure thing.

Perhaps that was true in John D. Rockefeller's day. But with no control of commodity prices, soaring costs and stiff foreign competition, and with smaller, more elusive reservoirs located in increasingly hard-to-develop places, the U.S. industry has had to turn to technology.

Technology is the great enabler that has made exploration more effective, drilling more efficient and production more prolific. At the same time, technology has made drilling and producing oil and gas safer and far less intrusive to the environment.

Oil-rich OPEC held the rest of the world hostage in the 1970s with its infamous oil embargo, driving prices up, but it does not control the market as tightly any more. In today's environment, companies develop business strategies for several different price scenarios, taking into account the cost of capital and regulatory compliance. Then they go about attempting to control the two things they can influence—their exploration success, and their drilling and production costs.

This is where technology comes in. To use an analogy, the development and use of oilfield technology closely parallels the conquest of space. From the early days of the Wright brothers, the technology of flight has increased exponentially. The same is true for exploration and production of oil and gas.

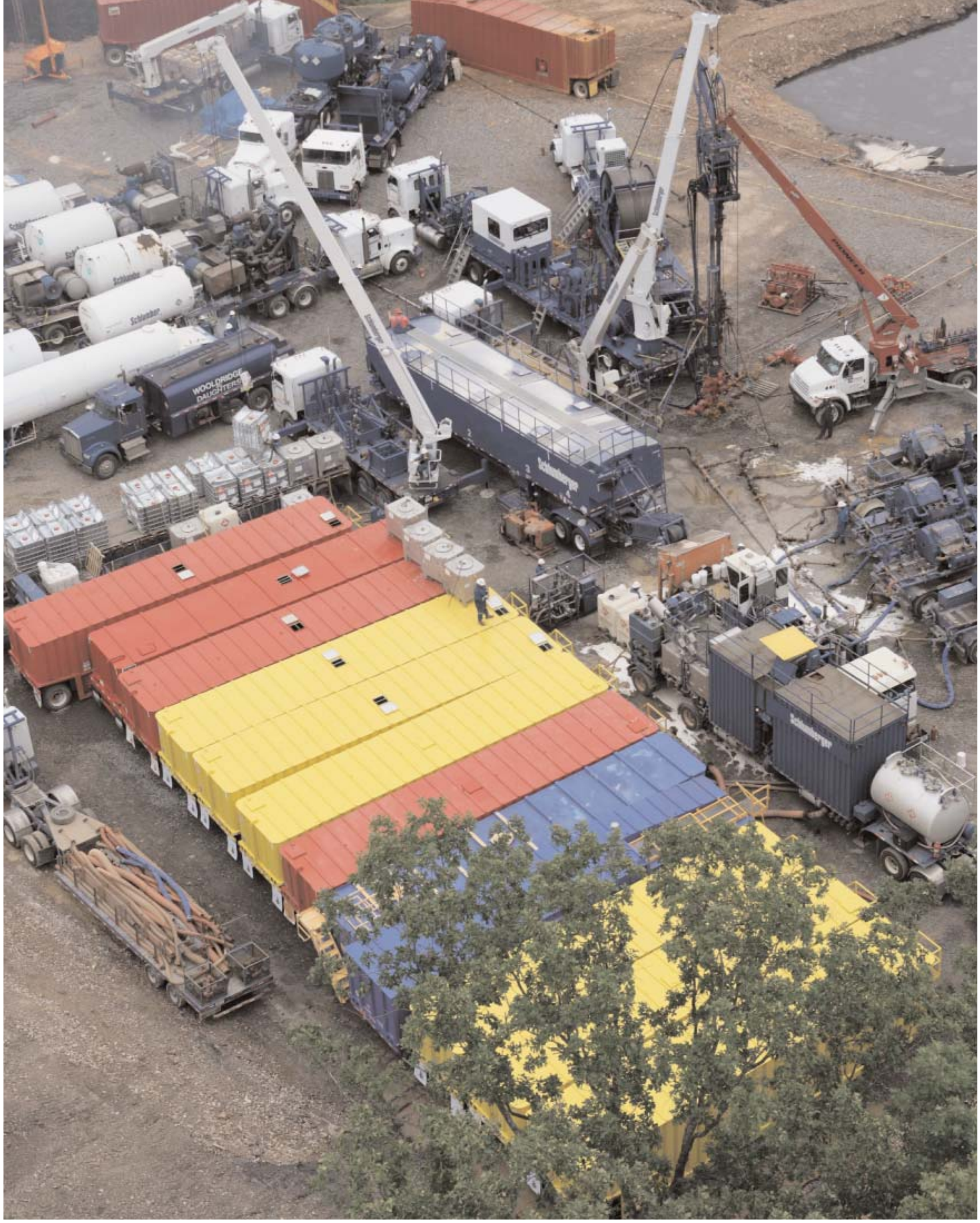
For example, until the 1980s only one in 10 exploratory wells—called wildcats—were successful—that is, they found economically recoverable amounts of hydrocarbons. Today, thanks to improved technology, about 25% to 40% of rank wildcats are successful, and in some states, the success ratio for development wells is much higher.

Development wells are those drilled after exploratory wells have indicated hydrocarbons. Is is often from development wells that oil and gas are produced. In the Appalachian Basin, many companies report drilling success ratios of 80% or 90% when drilling development wells to develop a field after the initial wildcat "comes in."

Often discovery wells prove to be in locations that prove to be sub-optimal for efficient production of the reservoir, so several develop-

A worn drillbit that was at work in the Barnett Shale of northeast Texas. Several drillbits may be needed before reaching target depth.

The array of equipment needed to carry out a frac job is impressive. In addition to a vast network of pipe at the surface, there is a fleet of pumping trucks, truck-mounted blenders, sand containers and fracture-fluid tanks and other support vehicles. Massive amounts of fluid are pumped into the well to crack the rock and improve flow.



ment wells are drilled to fully exploit the discovery. The original discovery well may be deemed unsuitable for production and will be plugged.

Since the beginning of the new millennium, commodity prices have soared and held steady at unprecedented levels. Prices reflect strong increases in global demand as well as threats to supplies.

Threats are natural, like hurricanes that can shut down offshore production, or political, like the crisis in the Middle East, or the actions of unstable governments. Costs have risen as well, because the new technology required to drill and produce from increasingly difficult areas is not cheap. Companies are now pursuing the prize in waters as deep as 10,000 feet (3,300 meters) and are going after unconventional gas resources, in tight gas reservoirs, in shales and in buried coal seams.

A new potential gas resource is being explored called methane hydrate. Methane hydrates consist of hydrates that are unstable frozen clusters consisting of a molecule of methane, completely surrounded by several molecules of frozen water. They exist in great quantities all over the world in a natural stable-state only under specific conditions of pressure and temperature. If they are removed from their stable environment, they thaw and the methane escapes to the atmosphere.

Researchers around the world are aggressively pursuing the development of enabling technology that will permit safe, commercial recovery of methane gas from hydrate deposits. So far, they have resisted all efforts by companies eager to develop them for commercial purposes. Costs of technology to solve this production problem will be steep.

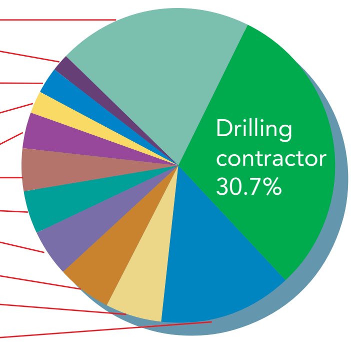
Upon developing a prospect, there are several cost-risk points at which a company must decide whether to continue: Is the prospect worth drilling? And after a discovery well is drilled, are the initial, visual results worthy of obtaining more sophisticated test results? If, yes, then, do these results indicate the prospect is worth completing and bringing into production?

In every case, the decision to proceed must be weighed against the cost of the added work that must be done as well as economic factors dictated by access to transportation (pipeline, river, road or railroad) to a refinery or consumer concentrations.

Costs to Drill & Equip a Well

Purchased items:

Miscellaneous	20.0%
Wellhead equipment	1.8%
Special tool rentals	2.7%
Drill bits	2.3%
Logs & wireline testing	3.7%
Formation treating	4.4%
Road & site preparation	4.4%
Cementing	4.8%
Supervision/overhead	5.6%
Drilling mud/additives	5.8%
Pipe (casing & tubing)	13.7%



Source: Independent Petroleum Association of America

The drilling rig, the largest single cost of drilling a well, is paid for by the day or by the footage drilled. That's followed by drill pipe and tubular goods.

Drilling the well

With a few notable exceptions, the basic technique of drilling a well has not changed much. Based on data from surface exploration techniques such as 2-D and 3-D seismic, geologists and geophysicists decide on suitable acreage for drilling. Companies then secure a lease from the landowner, or from the appropriate authority in the case of federal or state land or offshore leases.

They contract a drilling rig. Contrary to popular opinion, oil companies do not have their own rigs, relying instead on an experienced cadre of drilling contractors who supply the equipment and workers to drill the well for a specific day rate.

Modern rigs have banks of diesel-driven generators to provide the electrical power that lights the rig and drives the drill. The drilling function can be simplified by grouping it into two systems: the hoisting/rotating system and the circulating system. The former consists of the familiar derrick with its bright yellow block and cable hoist that trips the drill pipe into and out of the hole and supports its massive weight during drilling.

Rotating is accomplished by a rotary drive traditionally located on the drill floor, but more recently located atop the drill string—the so-called top drive. Top drives are a perfect example of how technology has improved safety and efficiency by reducing the number of times—by a factor of three—the drilling activity must pause to add a joint of pipe.

The circulating system pumps heavy drilling fluid down the drill pipe to cool and lubricate the bit, float rock cuttings to the surface, and control well pressures. Drilling fluid—commonly called mud—is really a high-tech formula containing chemicals that interact with the rock formations to ease drilling and protect the borehole wall. The high pressure imposed by the heavy column of mud balances formation pressures, and prevents the influx of well fluids or gas into the borehole.

This prevents the catastrophe known as a blow-out and is usually sufficient, but for added safety, each rig has a stack of valves just beneath the drill floor or on the seabed called blow-out preventers (BOPs) that can be closed to seal the well in an emergency. Drilling mud containing rock cuttings circulates up the outside of the drill pipe to the surface where it is filtered, de-gassed and recirculated.

Reducing drilling costs

The most notable applications of technology to reduce drilling costs have been in the areas of automated pipe-handling, improved drilling rates and geosteering, whereby real-time geological data are used to steer the bit into the target reservoir and keep it there.

As much as 40% of non-drilling time is spent handling pipe. Now computer-driven machines are taking over this time-consuming and dangerous job. Drilling rates are facilitated by new bit designs and by the use of underbalanced drilling, whereby the well is allowed to flow under controlled conditions while it is being drilled.

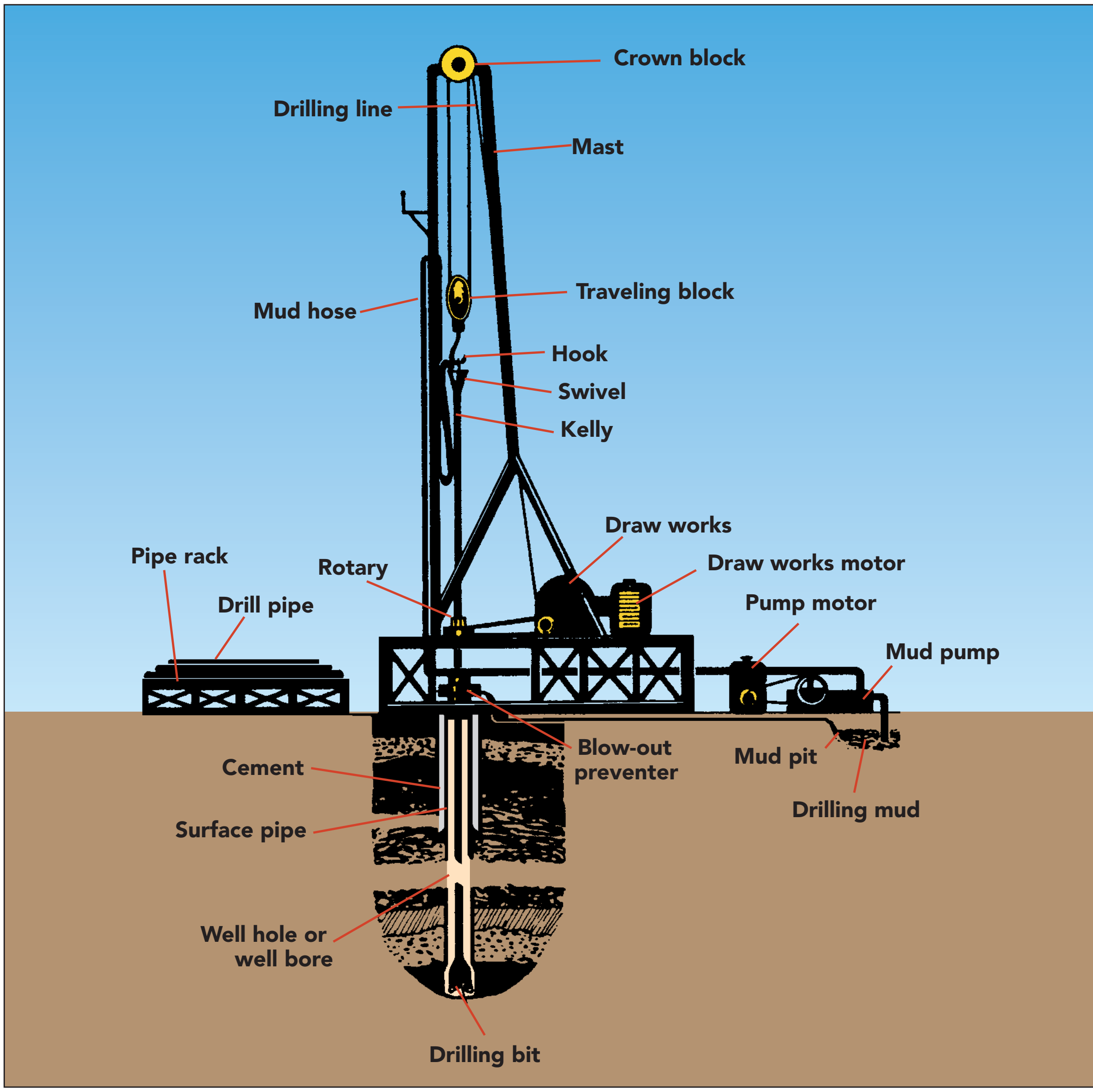
New instrumented bits allow dozens of critical measurements of formation and drilling parameters to be acquired and transmitted in real time to the surface. This improves drilling efficiency and accuracy. Finally, years of painstaking research have yielded environmentally friendly drilling and completion fluids as well as closed circulation systems, and most offshore locations follow a zero-discharge policy, meaning absolutely no well or rig effluent is put into the sea.

Some things never change, however. Drilling is still a demanding, 24-hour-a-day job that must be accomplished safely and efficiently in all kinds of weather in some of the world's most inhospitable locations.

Testing the well

Since the beginning, oil companies have tried to evaluate their wells to answer these basic questions: Is there oil or gas? How much? Can it be produced technically, and economically? How fast? For how long? Should we complete this well, or abandon it now before spending

Modern drilling rigs often include automated pipe-handling equipment, computerized controls, thinner pipe (called coiled tubing) and other new equipment to improve efficiency and safety, or speed up the time it takes to reach to total target depth. Technology enables companies to drill into high-pressure, high-temperature zones as deep as 25,000 feet and offshore wells just as deep—in water up to 10,000 feet deep.



any additional time and money? Where should the next well be drilled?

The answers to these questions are fundamental to every economic decision that must be made over the life of the well or reservoir. Formation evaluation technology has kept pace with drilling technology with new sophisticated well logs, cores and well tests.

Periodically during drilling, the drill pipe and bit are removed, i.e., "tripped" out of the hole, so electronic instruments can be introduced into the well on an electrical cable called a wireline. The measurements made by these instruments are plotted on a chart called a log. Alternatively, some logging data can be acquired while drilling, as noted earlier.

Logs are used to determine the location and thickness of hydrocarbon-bearing strata and indicate their orientation in geospace. Cores, once the only sure way to determine formation mineralogy and physical characteristics, are formation samples cut and recovered from the rock. Cores are now being challenged by sophisticated high-resolution nuclear spectroscopy log images to accurately describe formation texture, porosity and permeability.

Well tests help determine reservoir volumetrics as well as pressure and flow rate of the well once it is placed on production.

Information is the key. Now computer databases are constructed from the outset, increasing reservoir knowledge with compatibly scaled data as each measurement is taken. This knowledge base facilitates decision-making and reduces risk. Virtually every decision is prefaced by a cost-benefit analysis that projects its economic effect. Today, sophisticated computer reservoir models can be integrated with dynamic surface-production-system models to simulate the entire production system from pore to export pipe.

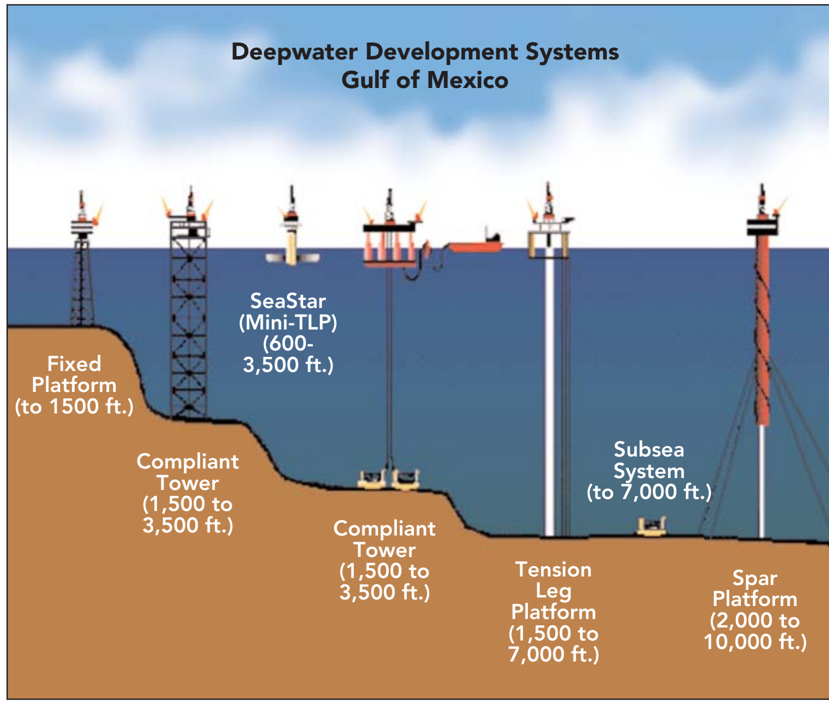
Real-time downhole test data can be transmitted via satellite from the field back to a company's headquarters—even in another country—so that scientists, engineers and managers at home base can evaluate the well and make the proper decisions.

Completing the well

As the well reaches its completion phase, decisions become easier because discounted cash flow models can be used to compare the incre-

*Facing page, Kerr-McGee Corp.'s **Global Producer VIII** is a floating production, storage and offloading (FPSO) ship that receives production from Bohai Bay, offshore China.*

Development systems produce oil and gas from wells. They enter the picture after rigs drill the wells and they are completed. Offshore, costs dictate that entire fields be produced from as few facilities as possible. One platform may serve 20 or more wells, for example. In the Gulf of Mexico, a variety of development systems are used, depending on water depth. The spar system can be used in ultra-deepwater. (Source: Minerals Management Service)



"Intelligent wells" …contain surface-adjustable downhole flow-control devices, so…flow rates can be optimized without having to perform a costly intervention.

mental benefit of each expenditure with the out-of-pocket cost. The immediate effect of technology improvements can be felt as the well is cased and casing is cemented in place to achieve hydraulic isolation of producing formations.

New expandable casing technology has been developed to reduce the cost of casing the well, and improved cements provide a higher margin of safety at less cost. New, deep-penetrating perforating guns fire explosive charges downhole, piercing the casing of the wellbore, the cement and the rock itself to provide flow paths for the hydrocarbons to enter the well and flow to the surface.

Finally, a string of production tubing and a packer is run downhole to provide a high-pressure conduit for production and the well is topped by a system of valves called a "Christmas Tree." Often the drilling rig is released once casing is set, and completion is accomplished with a smaller, less expensive unit.

"Intelligent wells" are increasing in popularity. These contain permanent monitoring sensors that measure pressure, temperature and flow and telemeter these data to surface. More importantly, these wells contain surface-adjustable downhole flow-control devices, so, based on the dynamic production information from all the wells in the reservoir, flow rates can be optimized without having to perform a costly intervention.

Wells that do not have sufficient natural formation pressure are produced by new high-tech electrical submersible pumps. These contain sensors that measure pump performance and efficiency, and telemeter the information to the production-operations center. The most significant result of these improvements is optimized production rates and extended reservoir life.

Well stimulation

Regardless of the quantity of hydrocarbons present, oil and gas wells do not always behave as we would wish them to. Some require extensive, and expensive, treatments before they will produce economically. Sometimes the subsurface formation must be washed with acid to clean out clay or other materials that are clogging the pores and impairing flow.

In formations with low permeability such as limestones, hydraulic fracturing is used to crack the rock and create a greater area of flow between the wellbore and formation pores. Conversely, in unconsolidated sandstones, screens must be placed within the well to keep sand from flowing into the well bore, clogging it and eroding the tubulars. Each treatment can be accurately costed, and justified in advance, using cash flow modeling based on incremental added production.

Where natural reservoir pressure is lacking, wells will not flow to the surface and must be assisted by pumps or artificial-lift systems. Lifting costs can be considerable, and must be considered along with finding and development costs, which are those expended to this point.

In the United States, average lifting costs are about equal to average finding/development costs, making many wells uneconomic. Complicating things is unwanted water production. More often than not, water is co-produced along with the oil or gas. Not only does each barrel of water produced mean one less barrel of oil, but the water must be safely disposed—it is usually salty and of no value for drinking or irrigation.

Typically the water is pumped into a nearby

A DRILLING GLOSSARY

Blow-out An uncontrolled, accidental release of well pressure, either to the surface or to another formation (in this case, called an underground blow-out).

Blow-out preventer (BOP) A series of valves, which offshore can be as high as 50 feet, to control the well and prevent a blow-out.

Casing Steel pipe used to protect the wellbore from caving in. When casing is cemented in place, it forms a hydraulic seal with the rock formations, preventing well fluid from migrating up or down the outside of the casing. It also keeps the well fluids separate from groundwater sources adjacent to the wellbore.

Circulation Analogous to the human circulatory system, mud is pumped into the well from a reservoir called a mud pit. It circulates down the inside of the drill pipe, flows out through ports in the bit and circulates back to the surface up the outside of the drill pipe, where it is filtered, de-gassed and returned to the pit.

Fishing Slang for retrieving pipe, tools, cable or objects that have been dropped into the well.

Fracturing (frac job) If the target reservoir lacks sufficient porosity or permeability to produce on its own in commercial quantities, this stimulation technique can improve the flow. Enormous pressure is applied to the reservoir by pumping in massive amounts of fluid (water or polymer) to enlarge the channels between pores in the rock.

Kick An unplanned influx of formation fluid into the wellbore, caused by the unexpected presence of hydrocarbons.

Lost circulation Leak-off of mud into a subsurface formation or through a hole in the well casing. Can be stopped by circulating plugging material similar to radiator stop-leak used in automobiles.

Mud Mixture of water and chemicals that occupies the borehole during drilling or completion of a well. Its main task is to exert hydrostatic pressure on the reservoir to balance the natural formation pressure and prevent an accidental influx of formation fluid into the borehole. It prevents the sides of the well from caving in as the hole is cut. And, it transports the rock cuttings from the bottom of the hole to the surface, where the geologist can examine them for clues as to the type of rock being penetrated.

Packer A mechanical seal between tubing and casing, usually set just above the producing formation.

Perforating A downhole perforating gun, lowered by wireline, that fires shaped charges through the casing into the desired rock formation, resulting in perforations through which reservoir fluids may flow into the wellbore and up to the surface.

Plug & Abandon (P&A) When a well is depleted of economically recoverable oil and/or gas, a permanent plug is set to seal the bottom of the well, as much casing as possible is recovered, and the surface location is restored to its original condition. The well is abandoned and a report is filed with the governing authority.

Seismic exploration Sound waves are pulsed into the earth. They reflect off subsurface layers and the reflected waves are processed to create a subsurface image of the earth from which promising rock formations can be identified for potential drilling.

Spudding The act of beginning to drill a borehole, usually starting with driving a piece of large diameter pipe (casing) into the ground (or seabed) to guide the bit and protect the surface immediately surrounding the borehole.

Trip The act of removing the drill pipe from the borehole (to put on a fresh drillbit, for example) and/or reinserting the pipe into the hole. Each phase has a name: tripping-out, tripping-in or round-tripping. This function is usually done manually by roughnecks, or it can be done by automatic pipe-handling equipment.

Tubing High-pressure pipe runs inside the casing through which the oil or gas is produced.

Wildcat An exploratory borehole drilled in virgin territory, usually at least a mile or two away from the nearest production of oil or gas. A rank wildcat is a well drilled many miles away from the nearest production and is inherently more exploratory in nature, and thus more risky. On the other hand, the rank wildcat may tap into a virgin subsurface zone that has high pressure and offers much greater daily oil or gas production.

Workover An oilfield term meaning "overhaul." Periodically, wells must be worked over to address cleaning, wear and corrosion of the downhole equipment, or pressure issues. Special light-duty rigs called workover rigs perform this task at a fraction of the cost of a drilling rig.

Drilling is still a demanding, 24-hour-a-day job that must be accomplished safely and efficiently in some of the world's most inhospitable locations.

injection well, or it is trucked away from the surface location, to be safely disposed elsewhere, according to local or state regulations. New technology allows oil and water to be separated downhole and the unwanted water is reinjected into a nearby nonproductive formation—never reaching the surface.

Workovers

Throughout the life of the individual well and reservoir, periodic interventions are made to acquire production data and perform overhauls, called workovers. Slim logging tools can pass through the production tubing and make flow measurements. The result of this allows remedial steps to be taken to optimize flow.

As long as they can be economically justified, elaborate enhanced-production schemes can be launched to improve the ultimate recovery factor—total percentage of recoverable oil from the well—which can reach as much as 70% in some cases.

Enhanced oil-recovery (EOR) methods include water-flooding, where water is pumped into injection wells drilled around the flanks of the reservoir, forcing more oil out the central, producing well. Other EOR techniques include steam-flooding or CO2 (carbon dioxide) injection that melt or dissolve viscous oil deposits and improve their flow characteristics.

Even more exotic methods involve fire-flooding, in which a downhole fire is started to melt heavy oil, or the injection of microbes that eat the polymers that are binding the oil

The goal (in drilling) is not just to produce oil or gas…Savvy companies also try to achieve an adequate return on capital employed.

HOW TECHNOLOGY AFFECTS ECONOMICS: THREE EXAMPLES

As oil companies apply new or improved technology and best practices, and learn more about a particular play by drilling more wells, they are often able to reduce either the time it takes to drill and complete a well, or reduce the costs, or both. This can help them offset any commodity price weakness they may experience during the time they are developing a field.

The goal is not just to produce oil or gas, thereby increasing the company's proved reserves, or increasing its immediate cash flow from production. Savvy companies also try to achieve an adequate return on capital employed (ROCE). A company is essentially standing still if it spends $1 to achieve $1 of income. Even if technology fosters improvements that are less than dramatic, that still matters. Here are three real-life examples from early 1999:

• In Colorado's Denver-Julesburg Basin, northeast of Denver, operators deepened existing wellbores that yield from the Codell formation to get new gas production from the so-called J Sand, a zone that is about 500 feet deeper.

A grassroots well drilled to the J Sand costs about $330,000. Deepening an existing well to that depth is cheaper, and used to cost $250,00 to $270,000, including fracture-stimulation.

But that cost was brought down to $200,000 per well. What's more, drilling times were cut from about 30 hours per well to about eight, creating significant savings and making the play more economic. The wells produce an average of between 600- and 800 million cubic feet of gas in their productive lives.

• In Alaska, the economic threshold for field development on the North Slope used to be 250 million barrels of recoverable oil, a fairly large field, due to high drilling, production and transportation costs. However, thanks to improved technologies and practices, producers are now able to produce ever-smaller fields, called satellite fields, often using tie-backs to existing surface facilities nearby.

The industry has managed to reduce the size of an economically viable field there from 250 million barrels to 50 million, according to a former North Slope field developer, Arco, which is now owned by BP. This has allowed the development of reservoirs previously thought not worth the expense, and increased U.S. oil output.

• At Wytch Farm, along the southern coast of England, BP applied technology to produce extremely deep offshore wells that are drilled directionally from land. These wells have reached a total depth of 31,355 feet: a vertical depth of 5,887 feet and a horizontal departure from the wellbore of another 29,324 feet. That's almost six miles of subsurface drill pipe that needs to be controlled and kept in the target producing reservoir!

Through process changes, technology, teamwork and advanced planning with the service and equipment vendors, BP was able to reduce the time it takes to drill such a long horizontal well by 40%, drilling and completing the well in a record-breaking 81 days. Measurement-while-drilling and logging-while-drilling tools were used.

in place.

Each of these schemes undergoes a cost/benefit analysis before attempted. Even under the best of scenarios, a well may only produce 10% to 20% of the oil in place in its lifetime, absent stimulation.

Offshore

Offshore, costs dictate that entire fields be produced from as few facilities as possible. This is especially true in deep waters or in harsh environments such as the North Sea. Tall jacket platforms sit on the ocean floor and serve as production facilities for 20 or more wells. The wells all come together at the surface, but branch out in all directions underground to tap the farthest reaches of the reservoir.

In harsh environments, huge gravity-base structures combine the roles of supporting the production facilities and serving as storage tanks for the crude oil. Recently, tension-leg platforms and spars have been introduced.

These are floating platforms tethered to the ocean floor, but free to move about with wind and current. They can often be economically relocated and re-used for other fields when the original field is depleted.

With deepwater discoveries, an entirely new technology has made production economical. Floating production, storage and offloading (FPSO) vessels are converted oil tankers with production and processing equipment on deck. These receive oil from flexible risers connected to gathering stations and subsea wellheads located on the sea floor. They process the crude and store it until offloaded by a shuttle tanker.

In highly developed areas such as the Gulf of Mexico, FPSOs may not be as economical as running a subsea pipeline several miles from the wellhead to connect to a fixed platform in shallower waters. Subsea connectors as long as 100 miles are in use today in the Gulf of Mexico.

Current challenges

In the United States, producers face stiff challenges. More than half of the country's oil now comes from "stripper" wells, which produce 10 barrels of oil per day or less. If oil fetches $11 or $12 per barrel at the wellhead as it did in the late 1990s, then most of these wells are uneconomical, once finding and lifting costs and taxes are factored in.

However, if a well is abandoned, it might never be brought back on production. So, oil companies— most of them small independent operators— are faced with a real dilemma. They can try to hang on and hope for higher prices, they can invest in expensive cost-cutting schemes with little hope of a quick recovery, or they can shut-in their wells.

Even with today's high prices, it's a gamble. No one knows how long high prices will last. Should the well's owner invest millions to try to improve a poor producer? Will the owner be able to recoup the investment before the next down-cycle?

Compounding the problem is the intensification of natural decline rates from existing wells. Over time, whether it takes four years or 30 years, every well will produce less and less until it is no longer economically viable.

U.S. reserves are being depleted faster than ever before. More discoveries are needed and more technology is required to improve existing productivity. Americans are going to be asked in the not-too-distant future if they are willing to accept importing as much as 75% of their oil from sources abroad.

What national security and economic risks does this imply?

—Dick Ghiselin

Offshore facilities, such as this production module for the Cameron Highway oil-pipeline system in the Gulf of Mexico, can be huge, and expensive, structures.

WHO SETS OIL AND GAS PRICES?

Once the well begins flowing in commercial quantities, the revenues begin—and so does a price roller-coaster.

It's sad but true for oil and gas producers, but commodity prices are rarely, if ever, set at the wellhead. Just as farmers don't control the price of wheat or ranchers of cattle, energy producers also are price-takers, not price-makers.

They operate at the mercy of a host of unpredictable domestic, international, economic and political factors beyond their control. Even the weather affects oil and gas prices. No wonder cash flows can vary greatly.

Studies show that of all commodities—wheat, sugar, orange juice, pork bellies, platinum, copper, gold, whatever—oil, gas and electricity are the most volatile of all.

Their daily prices on the New York Mercantile Exchange (Nymex) change more often, and to a greater degree, than that of other commodities. This in turn affects the price that buyers of the product will pay at the wellhead. Producers can mitigate this volatility, in part, by price-risk management (commonly called hedging) or by selling forward a portion of their production at an agreed price (volumetric production payments or VPPs).

Over time, the correlation between Nymex crude oil prices and the cash or spot price for West Texas Intermediate (the U.S. benchmark crude traded on Nymex) has proved to be very tight.

That price is formed by a complex set of factors, not the least of which are perceptions of traders and speculators. As the old joke goes, when traders from Long Island emerge from the subway, Manhattan's weather sets the tone for that day's trading. More seriously, analysts note the affect on Nymex of speculative hedge funds and others who can move the price based on their own perceptions. When oil can swing by as much as $1.50 per barrel in one day, that's not only world supply and demand affecting the price, it's someone's perception, fear or greed.

Who trades on Nymex? Oil companies, refiners, end-users such as airlines and manufacturers, and oil and gas marketers involved directly in the industry who understand the fundamentals, typically hold about 60% to 70% of the

Energy traders on the floor of the New York Mercantile Exchange use voice and gestures to indicate buy and sale orders for oil, natural gas, gasoline and heating oil.

Uses Of Hydrocarbons

Beside the generation of energy in electricity-generation plants, ships, automobiles and airplanes, there are some surprising uses of hydrocarbon-based products and petrochemicals.

Examples include lipstick, preservatives, contact lenses, antihistamines, shampoo, faux leather jackets and knit suits, pharmaceutical capsules, dyes, housepaint, insecticides, perfume, rope, glue, countertops, fertilizer, roofing, candles, shaving cream, dentures, crayons, ink, golf balls and bandages.

crude contracts on any given day. The rest are held by speculators, hedge funds and Wall Street investment houses, and by the odd-lot holders of a small number of contracts. Each day they react to weather conditions, global and national news events, and weekly and monthly reports from various agencies.

Some of the most closely watched data on international supply, demand and storage come from three sources: the International Energy Agency (IEA) in Paris; the American Petroleum Institute, a Washington-based trade group; and the U.S. Department of Energy's Energy Information Administration (EIA).

As the world produces about 84 million barrels per day, and the U.S. produces about 21 trillion cubic feet of gas per year, it is difficult to monitor and measure specific production and demand numbers. It is also difficult to track barrels or cubic feet that are in storage owned by governments and individual companies, and barrels that are in transport on the high seas.

In the end, all this leads back to the wellhead in the field, where wholesale oil and gas buyers and brokers post the price they will pay each day. Typically they arrange to buy for a 30-day period, as negotiated with the producer. Increasingly, these spot cash prices are tied to the closing price recorded on Nymex a day or two earlier.

No. 2 heating oil began trading on Nymex in 1978, crude oil futures in 1983, natural gas in 1990, and electricity in 1996. Instantaneous price transparency and computerized communication affect the worldwide price each day and in overnight trading as well.

The vast majority of oil and gas traded on Nymex is never delivered. Instead, the trade is closed, or liquidated, by assuming an equal and opposite position in the market. What's left is

If delivery is taken…, oil must be delivered at Cushing, Oklahoma, where many major oil pipelines intersect… Gas must be delivered at the Henry Hub, a gas pipeline intersection near Erath, Louisiana.

FACTORS AFFECTING PRICES

Going Up From the demand side, the global or U.S. economy improves, or turns out to be more robust than was forecast, boosting the need for oil used in transportation, oil or gas in manufacturing and petrochemicals, or other. A colder-than-normal winter hikes demand in Canada, U.S, Europe, Russia and Japan. A hotter-than-normal summer boosts air-conditioning demand.

From the supply side, global oil production or the amount in storage is lower than forecast, lagging demand growth. The guesstimates were wrong. Unexpected and/or temporary production shortfalls occur due to hurricanes in the Gulf of Mexico, problem wells, disappointing drilling results, project delays in bringing new production to market, pipeline restraints, or civil unrest in producing areas such as Nigeria or Colombia. The global or U.S. rig count falls unexpectedly, or by more than forecast, leading eventually to reduced available supply. Refinery are shut-in due to emergency or routine maintenance.

Geopolitics affect prices too. OPEC meetings and informal OPEC pronouncements spook oil markets and traders. War in the Middle East or elsewhere causes major supply disruptions. Guerillas sabotage oil or gas pipelines or other production facilities. State or federal regulation, legislation or tax changes make drilling and production more economic, thus boosting activity.

Going Down From the demand side, a slowdown in overseas or U.S. economies reduces demand for oil or refined products (diesel fuel, jet fuel, kerosene, etc.) or natural gas. A warmer winter than usual reduces the need for heating oil or gas.

From the supply side, global oil production or U.S. gas output turns out to be higher than forecast, or higher than demand, creating a supply glut. The amount of oil or gas in storage keeps rising, outpacing demand and creating a glut that takes time to be absorbed by the market.

Unexpected production increases occur due to more drilling, or more success per well drilled because of technology advances. Or, more companies enter the industry and start drilling. As oil prices rise, unaccounted-for inventories surface, curtailing the price rise.

Geopolitically, OPEC meetings or pronouncements spook oil markets and traders. State or federal regulations, legislation or tax changes suddenly make drilling and production less attractive.

The number of oil and gas contracts traded daily during the first nine months of 2005 averaged 242,609 and 78,139, respectively.

the paper profit or loss.

If delivery is taken of the product, oil must be delivered at Cushing, Oklahoma, where many major oil pipelines intersect and there are more than 21 million barrels of storage capacity. Gas must be delivered at the Henry Hub, a gas pipeline intersection near Erath, Louisiana.

Typical daily Nymex oil-trading volume exceeds the equivalent of 100 million barrels of oil, more than that physically produced each day. Nearly 1,000 traders may be frantically signaling buy and sell orders on a 25,000-square-foot floor that is dedicated to energy at the 133-year-old Nymex in lower Manhattan. Nymex handles about 75% of the daily trading in all energy futures contracts around the world.

The number of oil and gas contracts traded daily during the first nine months of 2005 averaged 242,609 and 78,139, respectively. In a study Nymex conducted in late 2004, the exchange found that hedge funds accounted for 3% of the volume of crude oil trades on the exchange and 9% of the natural gas trades.

—Leslie Haines

CRUDE À LA CARTE

They call it black gold, but it isn't always black and the amount of gold it puts in a producer's pocket varies greatly. In addition to global and national supply, demand and storage trends, Nymex prices, and the cost of transporting oil from wellhead to refinery gate, the physical attributes of the crude itself matter.

These attributes include the oil's viscosity, gravity (density as compared with water), and its sulphur, water and salt content. Crude gravity and volume vary with temperature.

Gravity refers to the density of the crude, expressed in a scale originated by the American Petroleum Institute. In the scale, water has a gravity of 10 degrees API. Liquids lighter than water (most crudes) typically have gravities numerically greater than 10, up to about 40. Hydrocarbons greater than 40-degree gravity may be condensates.

Some crudes, such as those found in parts of Oklahoma, Alberta and British Columbia, flow freely from the wellhead without pumps, and are so light in color and viscosity, they resemble white wine. They are almost ready to use in a combustion engine.

These crudes command top dollar. Other crudes, such as some found in California and Venezuela's Orinoco Basin, are so black, heavy and putty-like, they cannot be poured once they reach the surface. Water, gas, steam, carbon dioxide, nitrogen, polymers or other chemicals must be injected into the well first, to get the oil to the surface and through the pipeline. These oils command less money per barrel since they require more sophisticated and costly refining processes.

Lighter oils lend themselves to refining or manufacture of higher-priced products such as gasoline, jet fuel and kerosene. Heavier oils are refined into lower-priced products such as bunker fuel and asphalt.

A different price for crude is received based on its physical qualities and distance from the pipeline. (Photo by Nick DeSciose)

Myriad Crude Oil Prices ($/Bbl)

West Texas Intermediate:	$59.55
Louisiana Light Sweet:	60.39
Eugene Island:	57.17
Mars:	53.94
Poseidon:	53.95
HLS:	58.49
West Texas Sour:	54.50
Wyoming Sweet:	53.81
Basrah Light:	50.47
Bonito:	57.39
Alaska North Slope (California):	56.61
Canadian Lloyd Blend:	34.36
Canadian Mixed Sweet:	60.36
Canadian Light Sour Blend:	54.26
Canadian Condensates:	68.36
Terra Nova:	55.73
Hibernia:	56.68

Source: Platts North American Crude Wire, Nov. 8, 2005

RESERVES AND WRITE-DOWNS

The amount of oil and gas a company claims as its own can change due to commodity prices as much as by geological and technical factors.

How much is an oil and gas company worth? Measures such as cash flow growth, earnings per share (EPS) and return on capital employed (ROCE) tell only part of the story. What about the underlying assets themselves—the oil and gas reserves in the ground?

The current status and future potential of a company also are measured by the amount of reserves that are recoverable, the nature of those reserves, and the cost of finding and producing them. Some investors in oil and gas companies may be surprised to learn that how much oil and gas the company continues to own below the surface may change from year to year—not due to any change in how much oil or gas is actually there.

Through complex petroleum engineering studies and actual production history, a company grows more confident about the discoveries it has made. The more wells it drills in a given field or area, the greater its knowledge of the physical characteristics of the subsurface reservoir. The engineers can then determine which technologies to apply to maximize production in a cost-efficient manner.

Original oil and/or gas in place is the total, finite amount in the earth regardless of whether or not it can be technically or economically recovered. Recovery is a function of technology and market prices. Most oil wells recover only 10% to 35% of the oil and/or gas that is in place, without additional stimulation or special equipment. Gas wells do much better; it is not uncommon to recover 80% of the gas in place.

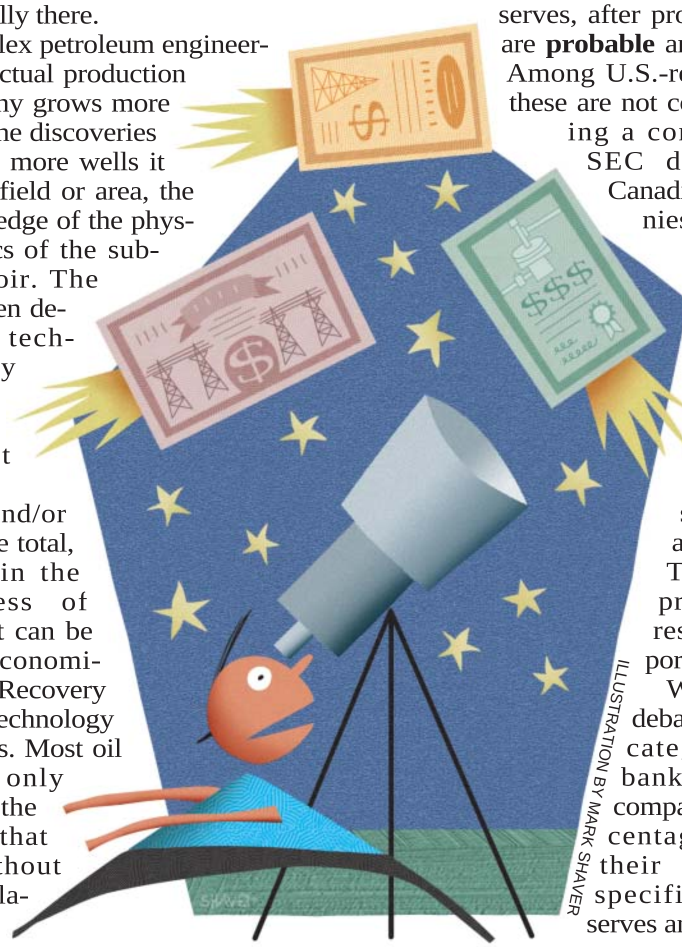


ILLUSTRATION BY MARK SHAVER

Proved oil and gas reserves represent the sum of two sub-classifications.

• **Proved developed** reserves can be recovered from known reservoirs in existing wells at today's prices and technology, using existing facilities. Sub-categories include proved developed producing (PDP) and proved developed nonproducing (PDNP).

• **Proved undeveloped** (PUD) reserves are expected to be recovered from new wells on previously undrilled leases, or from existing wells where a relatively major expenditure is needed to recomplete a well in a different zone.

• There are two additional categories of reserves, after proved reserves. These are **probable** and **possible** reserves. Among U.S.-reporting companies, these are not considered in evaluating a company's worth by SEC definition. Among Canadian-reporting companies, probable reserves are part of the calculation. Elsewhere in the world, various rules apply.

• The combination of the three reserve types in reporting "total reserves" is commonly abbreviated at 3P. The combination of proved and probable reserves would be reported as 2P.

While engineers may debate the finer points of categorizing reserves, bankers loan money to companies based on a percentage of the value of their proved reserves, specifically the PDP reserves and sometimes a small

A roughneck cleans the floor of a drilling rig. Shown is the hole, through which the well is drilled, and drilling mud.

portion of the PUD reserves.

Lower and/or slower production rates reduce the economic value of reserves, in terms of the time value of money. Higher costs also reduce value. The option value of undeveloped, probable and possible reserves is sensitive to a company's ability to find the needed capital, apply the right technology at reasonable cost, and install the right infrastructure to get the oil and/or gas to the surface and to market—surface or subsurface production facilities, processing or treating facilities, gathering lines and pipelines.

Each year, companies formalize this reserves-calculation process when they hire third-party engineering firms to audit their reserve numbers and revise them, based on a host of factors:

Technology and infrastructure How many of those barrels or cubic feet can be economically extracted now, using today's technology that is affordable to this particular company, and how much can be recovered in the future? What is affordable to an oil company that enjoys a good credit rating and thus access to low-interest debt may not be affordable to a small company that doesn't have the leverage and history to get low-cost capital.

What is the scope of the company's technical talent and access to the latest production science? It is more likely that ExxonMobil will successfully develop an ultra-deepwater Gulf of Mexico discovery in 10,000 feet of water and another 25,000 feet below the seabed that is 100 miles from the nearest existing pipeline infrastructure than the odds of a small oil and gas company doing so. In this case, the smaller oil company is usually a partner with ExxonMobil, and gets credit for its share of the reserves.

Are the new wells near existing gathering lines and pipelines, or many miles away? For example, zero credit would be given for gas reserves found in central Africa, where there is little market for the gas and infrastructure to get the gas to a thirsty market via a liquefied natural gas (LNG) terminal and tankers.

Do the wells require expensive fracturing or other stimulation before they can produce? Reserves associated with wells that may easily produce 10 million cubic feet of gas per day in South Louisiana would likely get full credit; waxy oil reserves in Utah that produce with great prodding would get less credit.

Commodity price What is the price of oil and gas now, and what might it be three years from now? Decisions based on oil prices of $60 per barrel look economic but they appear foolhardy if oil drops to $25 per barrel. The same holds when natural gas falls from $12 per thousand cubic feet to $4.

On the other hand, when oil and gas prices rise, the backlog of high-potential projects based on good science, but had to be shelved until better times, can finally be undertaken.

Can the company afford to fully develop the reserves using its own cash flow, or must it borrow, or bring in partners and trade away a percent of the total? Is this well uneconomic to produce now, or if oil or gas prices rise, will it be economic later?

Future cash flows are estimated based on future production volume and current spot prices, not the price that may actually prevail in the future.

Unless a company has an unusually high tolerance for risk, or deep pockets, it will postpone high-risk, high-cost wildcat wells in a low-price environment until the economics improve.

Economics may improve in four main ways: the price of the commodity rises, a new technology reduces finding, development or producing costs, the cost of capital falls or corporate overhead declines. Occasionally, state or federal tax relief may temporarily make drilling economics more attractive, which may cause a company to drill a well that was placed on the back burner.

Quality of reserves What percent of the reserves are now producing? If a high number, say 60% to 90%, a company is essentially liquidating itself, unless it can drill for or buy additional reserves. Does it have the cash flow to replace those reserves, or must it borrow?

Investors often get excited when a company makes a very large discovery, but the company may not have the personnel, equipment or capital to develop those reserves and bring them to market. After all, a barrel is worth zero unless it can be brought to the surface and sold to a buyer. Gas needs a market, and can be difficult to transport from remote places.

If only a few reserves are proved and producing, and the bulk are not yet onstream, then the company may be sitting on big potential—but only if it has the capital and technical know-how to proceed. Will the estimated cash outlays required exceed the cash that is estimated to come from oil and gas production, net of taxes, royalties, overhead and so on?

What is the reservoir quality? A steep decline curve of, say, 40% per year means the asset will quit producing oil or gas in less than three years—unless the owner can replace it with more drilling, or an acquisition. That has implications for corporate spending and debt levels.

Potential problems Most E&P companies conservatively book only the proved reserves—those reserves that are going to be developed (produced) economically in the near term, assuming existing technology and current spot oil or gas prices.

However, any number of events can materially change the reserve picture and the timing to production. Production may have increased, but not to the levels predicted, or not in the same timeframe. Or, sales agreements and pipeline hookups were delayed, meaning the reserves sat in the ground, proved but not producing.

Location Location and logistics also affect the dollar value of reserves. A barrel of oil in northeastern Utah is not worth the same as a barrel in Kentucky or in the Gulf of Mexico. A shallow well five miles from the nearest pipeline in South Texas costs much less to drill and produce than a deepwater oil well 150 miles south of New Orleans.

Ceiling test

The SEC requires public companies to present an audited reserve report in each year's annual financial statement. The estimated reserve volumes are based on proved reserves and the price of oil or gas at the end of the quarter or year.

Companies using the full-cost accounting method must value their reserves based on prices received at year-end. A company's net book value of its oil and gas, less related deferred income taxes, may not exceed a calculated ceiling. The ceiling is the after-tax future net revenues of the reserves, discounted 10% per year. Any excess is written off. Producers with higher costs generally are hit the hardest.

Measuring Gas

What's the difference between an Mcf and an MMBtu? One is a physical measurement; the other is a measurement of how much energy the natural gas contains.

An Mcf (thousand cubic feet) of natural gas produced from the Gulf of Mexico may contain additional chemical attributes that must be stripped from it (in gas-processing) before being sold to end-users, thus it actually contains somewhat less than a thousand cubic feet of sellable natural gas.

Meanwhile, an MMBtu (million British thermal unit) is the measurement of how much energy the gas can generate. This is a measurement of the natural gas once the impurities have been stripped away.

Natural gas is traded on Nymex in MMBtu, which is generally nearly the same as a thousand cubic feet but is more precise in its energy content.

Investors may ask an oil and gas company what is the MMBtu content of the gas the company produces—some contents are higher and some are lower than the equivalent of an Mcf.

Rarely is there a tremendous variation; however, there usually is some difference, and this affects the price the producer gets for the natural gas.

If the price of oil or gas has declined significantly at year-end, the company is forced to take a ceiling-test write-down in the dollar value and volume of its reserves.

Ceiling-test write-downs can cause a number of results:

• Since a producer uses lower commodity prices in its model, it winds up with lower revenues, which brings down the discounted present value of future net revenues. This may cause a loss for the year.

• When a lower oil or gas price is used in the model, some reserves become uneconomic to drill or produce, so the company has to take them off its books. If a producer happens to have very low operating costs, most of the reserves may stay on the books despite low prices. But if the properties were marginal to start with—i.e., low production volumes or high costs—the company can lose a lot of reserves, at least on paper.

• A write-down can hurt a company's capitalization ratio and cause it to breach its bank loan covenants. Banks lend based in part on a company's proved reserves. This can reduce the oil and gas companies' overall borrowing capacity.

On the plus side, the ceiling test forces management to examine closely and better understand the true nature of its assets.

—Leslie Haines

Lower and/or slower production rates reduce the economic value of reserves, in terms of the time value of money. Higher costs also reduce value.

HOW TO VALUE E&P STOCKS

What financial criteria should investors use when buying upstream oil and gas stocks? Analysts indicate there is more than one yardstick for picking winners.

As any investor has learned in recent market times, landing the big catch among publicly traded E&P stocks is a function not only of patience, but of applying the right financial criteria when analyzing the annual reports or 10-Ks of upstream independents.

Just what are these criteria? E&P analysts use several yardsticks to determine if a company's shares are worth buying. In the main, they pay attention most to these factors:

• A producer's present and potential cash flow per share;

• Total capitalization or total enterprise value/EBITDA (earnings before interest, taxes, depreciation and amortization);

• Full-cycle return on investment; and

• Share price versus a company's breakup value or appraised net worth.

"The managements of E&P companies aren't being judged by the market on their ability to generate net income, but rather on their ability to take the cash they generate from production and invest it in existing or new properties to improve the underlying asset value of their companies," says one Dallas buyside analyst.

Another market seer, this one in New York, agrees. "We consider annual earnings numbers an unreliable tool for comparing upstream companies. That's because some operators use successful-efforts accounting whereby they expense—or subtract from earnings—exploration costs in the same year they occur; those using full-cost accounting, on the other hand, fully capitalize and then amortize their exploration costs over future years.

"With cash-flow analysis, we add back in the exploration expenses for successful-efforts companies, thereby creating more of a level playing field—one that allows for similar comparisons."

But there's a more compelling reason why the analyst places a premium on cash flow. "That's what an operator must use (to fund drilling or acquisitions) to replace the reserves he produces in a given year. As such, it serves as a gauge of his ability to grow his asset base."

Echoes another Wall Street analyst, "The future success of upstream companies depends on their ability to ward off production declines by cost effectively finding new reserves with cash flow generated from current sales. Those that that can grow their cash flow by growing their production profiles are the ones that are going to improve their bottom line and the ones in which you want to invest."

E&P analysts, however, don't regard cash flow analysis as *the* stand-alone tool for measuring an upstream operator's investment worthiness. On the contrary, they believe an investor should also place a premium on a company's share price versus its net asset value (NAV).

"Every now and then, you come across a situation where an independent has hit a home run or is about to tremendously increase the underlying value of its reserve base—but the market hasn't recognized this yet in the company's share price," observes the Dallas buysider.

This was the case with Dallas-based Triton Energy in the early 1990s, just before it made its big oil discovery in Colombia's Cusiana Field, he points out. (The company has since been purchased by Amerada Hess.) "So it's well to consider *where* upstream operators are trading relative to their NAVs. In many cases, you'll uncover producers that are significantly undervalued by the market and hence, worth future scrutiny."

When valuing E&P companies, an analyst may focus on total enterprise value (stock market equity plus debt and preferred shares)/EBITDAX (earnings before interest, taxes, depreciation, amortization and exploration expenses).

"It's a debt-adjusted ratio that takes into account a company's unlevered cash flow," one analyst says. "That's a useful equalizer in comparative valuation analysis in that it eliminates the effect of varying high- to-low-debt capital structures on cash flow."

This valuation yardstick, also known as total capitalization/EBITDA, can be an eye-opener for investors. Here's a hypothetical example: Alpha Oil Co. and Beta Oil Co. both have EBITDA of $10 million. But while Alpha has $100 million of equity and no debt, giving it a total capitalization of $100 million, Beta has $100 million of equity and $100 million of debt, giving it a total capitalization of $200 million. Thus, the total cap/EBITDA multiple for Alpha is only 10 while the same multiple for Beta is 20.

Explains the researcher, “Having compared both companies on the same debt-adjusted cash flow basis, and having recognized the financial leverage of both and their ability to fund drilling programs, you’d rather invest in the hypothetical Alpha company with the total cap/EBITDA multiple of 10.”

Among other investment criteria, the Denver analyst also studies NAV to identify stocks that are trading below their inherent asset or liquidation value. “Similarly, scrutinizing stock price/discretionary cash flow helps identify stocks that are comparatively undervalued, this time on an after-interest, after-tax, cash-flow multiple basis,” he says.

In addition, he looks at cash flow per unit of production/finding costs. The reason? “This ratio is a good proxy for return on investment and implied growth rates.”

Warns the analyst, “An investor should be wary of operators with declining or flat production, high finding costs versus cash flow generated per unit of production, lack of high-growth-potential areas, and too much debt.”

Emphasizing yet another valuation metric, one Houston-based market seer places a high premium on full-cycle return on investment (cash flow per barrel equivalent divided by multi-year average finding costs).

“Cash flow growth means nothing unless a producer is making money on that incremental dollar that it invests,” he explains. “Calculating a full-cycle return on investment directs investors toward those companies that are making *efficient* capital investments and away from those that are making inefficient investments.

“Put another way, it helps investors avoid paying five times cash flow for upstream stocks with poor returns versus paying five times cash

…Pay more attention to how much maintenance capital spending is needed just to keep that company’s asset base flat—and (how much is) left over to grow….

A Total Cap/EBITDA Worksheet

	EBITDA ($Million)	Equity ($Million)	Debt ($Million)	Total Cap ($Million)	Total Cap/ EBITDA
Alpha Oil Co.	$10	$100	$0	$100	10
Beta Oil Co.	$10	$100	$100	$200	20
Gamma Oil Co.	X	Y	Z	Y+Z	Y+Z/X

The valuation yardstick known as total capitalization/ EBITDA can be an eye-opener for investors.

flow for those with tremendous returns."

When it comes to cash flow or NAV analysis, the analyst argues that investors should pay particular attention to underlying pricing assumptions for oil and gas, given the volatility of these commodities.

"The way we deal with the problem of volatility in our analysis is to use price-normalized cash flow and asset values, that is, we use historical five-year-average oil and gas price assumptions in our valuations—not current spot prices." This can lead to a better perception of investment opportunities, he points out.

Another caveat the analyst advances: when investors today scrutinize a producer's discretionary cash flow, they should pay more attention to how much maintenance capital spending is needed just to keep that company's asset base flat—and how much free cash flow is *actually* left over to grow that producer's reserve base.

"If two operators each have $100 of discretionary cash flow, and one of them has to use all of it just to replace what has already been produced, then that company is just standing in place," he insists. "If the other, meanwhile, has finding and development costs only half as much as the former producer, it's clear that's the one that's going to have the free cash flow to grow."

Yet another Houston-based analyst places a high value on breakup or NAV analysis. He points out that if an investor can buy a producer's reserves in the stock market for less than what an independent engineering report says they're worth, then there's an opportunity to make money as those reserves are produced and sold in future years.

"If the net present value of a producer's future oil and gas cash stream—plus the value of its other assets less debt—is $1 per share, and that company's stock currently trades at 50 cents per share, then I've discovered a stock that's selling for half its breakup value," he says.

Naturally, the analyst also focuses on cash-flow analysis—and with good reason. "You might be looking at the greatest bargain in the world as far as the discount-to-breakup value of a producer's reserves in the ground, but if the company doesn't have the money or wherewithal to produce and sell those reserves at a profit, then those reserves can't really be fully exploited."

And neither can the investment.

—Brian A. Toal

AN E&P BALANCE-SHEET GLOSSARY

Cash flow Annual net income (after-tax earnings) plus depreciation, depletion and amortization (DD&A), deferred taxes and other non-cash charges.

Cash flow per share Annual net income plus DD&A and other non-cash charges divided by number of common shares outstanding.

Cash flow multiple Stock price divided by annual cash flow per share.

Break-up value Also called liquidation or appraised net asset value. Represents the estimated net asset value of a company, assuming that all tangible assets, liabilities and preferred stock were liquidated.

Break-up value per share The estimated net asset value accruing to a company's common shareholders, assuming all tangible assets, liabilities and preferred stock were liquidated.

Discount to break-up value The percent of discount that a company's common shares trade at relative to that company's estimated break-up value per share.

Finding costs The costs incurred to find and develop oil and gas reserves, exclusive of lifting, operating and G&A costs.

Full-cycle return on investment Cash flow per equivalent barrel divided by multi-year average finding costs.

Total enterprise value Also referred to as total capitalization, it is the value of common equity plus long-term debt plus preferred stock.

EBITDA Earnings before interest, taxes, depreciation and amortization.

EBITDAX Earnings before interest, taxes, depreciation and amortization, and exploration expenses.

Total enterprise value to EBITDA Also called total capitalization/EBITDA. It is common equity plus long-term debt and preferred stock divided by EBITDA.

This ratio allows a company's cash flow to be viewed on a debt-adjusted basis, thereby taking into account the impact of financial leverage on that company's price/cash-flow multiple.

SPEAKING E&P

Codified and slang terminology can quickly be deciphered. Here's how.

These are definitions of some of the key terms that are used in oil and gas companies' investor presentations, press releases, annual reports and other documents. Investors who are new to investing in upstream energy stocks can find additional definitions of unique terminology in upstream companies' annual reports.

M is the Roman numeral for a *thousand*. So, production of 67 Mcf of gas per day is 67,000 cubic feet.

MM represents a *million* in the Roman-numeral system, so production of 67 MMcf of gas per day is 67 million cubic feet.

B represents a *billion*, thus production of 67 Bcf of gas per day is 67 billion cubic feet.

T represents a *trillion*, so proved reserves of 2 Tcf of gas are 2 trillion cubic feet of gas.

Bbl represents a *barrel*. Production of 80 Mbbl of oil per day is 80,000 barrels.

Cf represents *cubic feet* and is usually the measurement of natural gas.

Cfe represents *cubic feet of gas equivalent*. It is usually the measurement of the mathematical combination of natural gas and oil or gas liquids. The conversion is usually 10,000 or 6,000 cubic feet of gas per one barrel of oil or gas liquids. (The ratio usually reflects the recent market value of 1 Mcf of gas in comparison with 1 barrel of oil or gas liquids.) Thus, 10 MMcfe is 10 million cubic feet of gas equivalent. If the true mixture is 50% natural gas and 50% liquids (oil or gas) and the mathematical

The higher the (API gravity) degree, the lighter the oil and the greater the market value because it needs less refining.

ILLUSTRATION BY VON GLITSCHKA

A development well is drilled where there has been a discovery, as a result of an exploratory well…A development well is rarely a dry hole.

rate is 10:1, then 10 MMcfe consists of 5 MMcf of gas and 500 barrels of oil or gas liquids.

BOE is *barrels of oil equivalent*. It is usually the measurement of a mathematical combination of natural gas and oil or gas liquids. The conversion is usually 10,000 or 6,000 cubic feet of gas per one barrel of oil or gas liquids. Thus, 10 MMBOE is 10 million barrels of oil equivalent. If the true mixture is 50% natural gas and 50% liquids (oil or gas) and the conversion rate is 10:1, then 10 MMBOE consists of 500 Bcf of gas and 5 million barrels of oil or gas liquids.

Cf/d is *cubic feet of gas per day*. Another abbreviation of this is **cfpd**.

Bbl/d is *barrels of oil per day* or *barrels of gas liquids per day*. Another abbreviation is **bpd**.

NGLs are *natural gas liquids* and these are usually measured in barrels rather than in cubic feet.

Btu is a *British thermal unit* and is a measurement of stored energy, primarily used to describe the heat content of natural gas. One million Btu is generally the equivalent of 1,000 physical cubic feet; however, some natural gas contains fewer or more impurities than others and therefore has a higher or lower stored-energy content and, thus, market value. Natural gas is traded on Nymex in Btu rather than cubic feet.

API gravity is a measurement of the gravity (density) of crude oil and other liquid hydrocarbons by a system recommended by the American Petroleum Institute (API). The measuring scale is in degrees. The higher the degree, the lighter the oil and the greater the market value because it needs less refining. Some oils produced in North Africa and the Middle East, for example, have API gravity measurements of more than 40 degrees. Heavier oils, such as some produced in southern California, may have API gravity measurements of less than 20 degrees. The oil that is traded on Nymex is West Texas Intermediate, which is a middle-grade oil of approximately 32 degrees.

A **reservoir** is a porous and permeable subsurface formation that contains oil or gas and is surrounded by rock that separates the oil or gas contents from other reservoirs.

A **field** is an area that contains a single reservoir or related reservoirs with the same geological structural feature or stratigraphic condition.

A **trend** or **play** is an area or region where there is a great deal of drilling and production activity and involves a group of related fields and prospects.

An **exploratory well** is drilled to find oil or natural gas.

A **dry hole** occurs when no oil or gas is found in the exploratory well, or the quantity of oil or gas that was found is insufficient to justify the expense of bringing the well into production.

A **delineation well** or **appraisal well** is drilled near a discovery well to help define the boundaries of the oil or gas reservoir and to further assist in deciding whether to incur additional spending to produce the oil or gas. A delineation or appraisal well can be deemed a dry hole.

A **development well** is drilled where there has been a discovery, as a result of an exploratory well, and is usually drilled after delineation or appraisal. Oil or gas is produced from this well. A development well is rarely a dry hole.

Working interest is the percentage of ownership that the company has in a joint venture, partnership, consortium, project, acreage or well.

Farm-in or **farm-out** is an agreement in which the owner of a working interest in an oil and gas lease gives some or all of the interest to another party who wants to drill on the leased acreage. The party farming out the working interest usually retains a royalty or reversionary interest from the party that is farming in.

Gross acres or **wells** are the total acres or wells in which a working interest is involved. **Net acres** and **net wells** are calculated by factoring in working interest. For example, if a company's working interest in 100,000 acres is 50%, then its ownership is 50,000 net acres. If the company's working interest in 100 wells is 30%, then its ownership is 30 net wells.

A **PSC** is a production-sharing contract in which a host country receives oil or gas from an E&P company as a royalty payment. The E&P company usually bears all expenses of finding the oil and gas. If successful, the host country may contribute the expense of bringing the discoveries into production.

Net pay is the thickness of productive oil- or gas-saturated rock that has been encountered during drilling. A company may drill a 15,000-foot well and encounter 300 feet of net pay in several intervals of 100 feet each, for example. The development well is designed to produce only from the net pay.

A **prospect** is a lease or individual well that may be drilled because geology indicates it will probably be productive.

Prospective acreage is where there are geologic, seismic and/or other reasons to believe the subsurface may contain oil or gas. Drilling will be necessary to form a conclusion.

Proved acreage is where the existence of oil or gas has been proven by drilling exploration and appraisal wells.

For a comprehensive guide through the technical aspects of the upstream oil and gas exploration and production industry, see Fundamentals of Petroleum, *a publication of the University of Texas-Austin's Petroleum Extension Service. The service can be reached at 512-471-5940 or 800-687-4132.*

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