The Expanding Scope of Well Testing

Well testing has come a long way since the first drillstem test was run in 1926. From a simple composite packer and valve run on drillstring, the scope of well testing has blossomed into a broad array of sophisticated downhole and surface technologies.

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ArchiTest, CFA (Composition Fluid Analyzer), CHDT (Cased Hole Dynamics Tester), CleanSep, CleanTest, CQG (Crystal Quartz Gauge), eFire, E-Z Tree, InterACT, IRIS (Intelligent Remote Implementation System), LFA (Live Fluid Analyzer for MDT tool), MDT (Modular Formation Dynamics Tester), MFE (Multiflow Evaluator tool), OFA (Optical Fluid Analyzer), Oilphase-DBR, PCT (Pressure Controlled Tester), PhaseTester, PIPESIM, PLT (Production Logging Tool), PowerFlow, PVT Express, PVT Pro, Quicksilver Probe, SenTREE and UNIGAGE are marks of Schlumberger. PhaseWatcher and Vx are joint marks of Schlumberger and Framo.

Every E&P company wants to know what type of fluids its well will produce, what flow rates the well will deliver, and how long production can be sustained. Given the right planning, technology and implementation, well testing can provide many answers to these important questions. In one form or another, well testing has been used to determine reservoir pressures, distance to boundaries, areal extent, fluid properties, permeability, flow rates, drawdown pressures, formation heterogeneities, vertical layering, production capacity, formation damage, productivity index, completion efficiency and more.

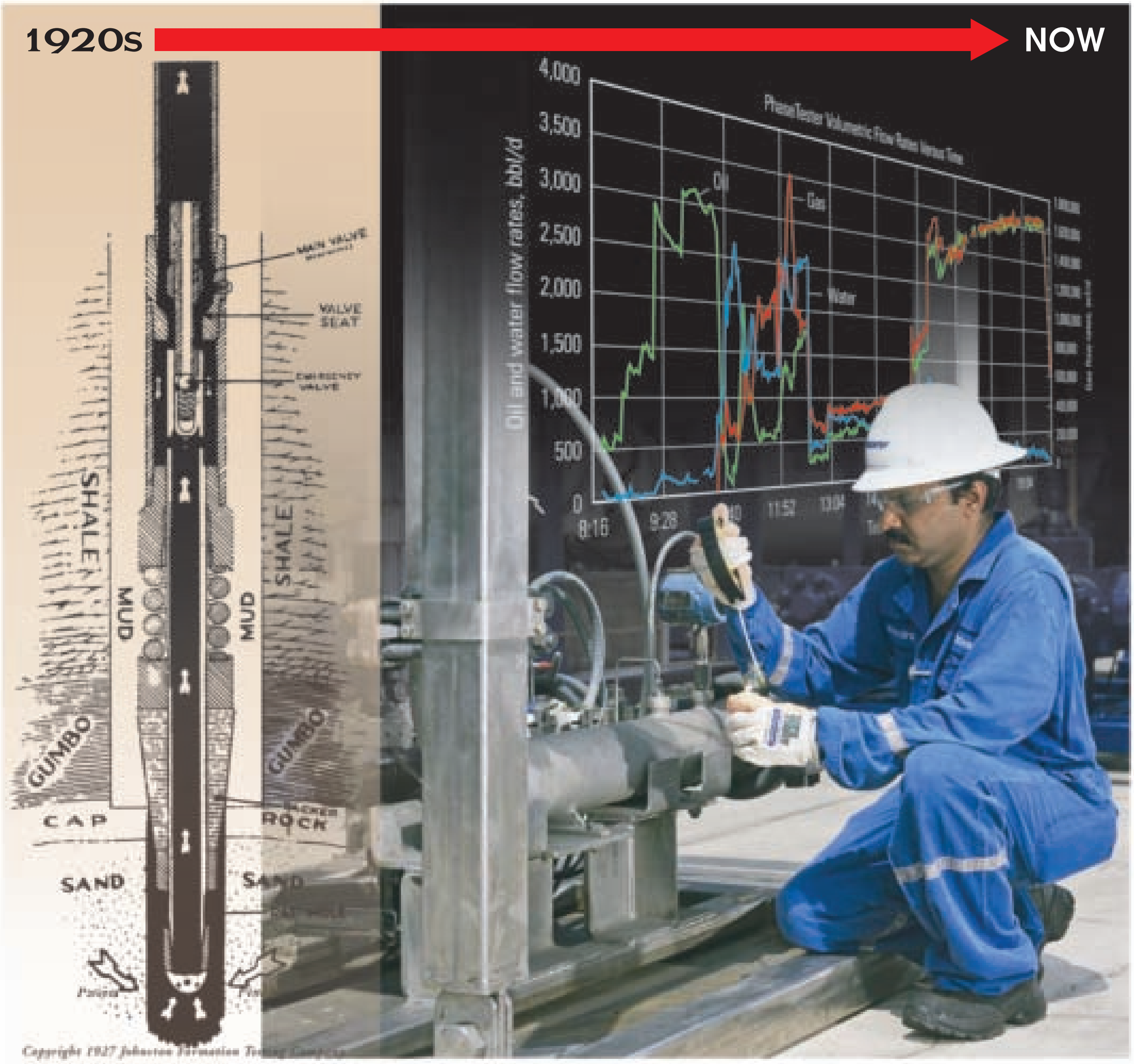
By measuring in-situ reservoir conditions and fluids as they flow from the formation, the testing process gives E&P companies access to a variety of dynamic and often unique measurements. Depending on the scale of a test, some parameters are measured at multiple points along the flow path, allowing engineers to compare downhole pressures, temperatures and flow rates against surface measurements of the same parameters (below). Through well testing, operators can extract reservoir fluid samples—both downhole and at the surface—to observe changes in fluid properties and composition between the perforation and the wellhead. This

Data Measurement Points

Surface Acquisition	
Flowhead	Pressure and temperature of tubing and casing
Choke manifold	Pressure and temperature
Heater	Pressure and temperature
Separator	Pressure and temperature; differential pressure across the gas orifice; flow rates of oil, gas and water; oil shrinkage; basic sediment and water; oil and gas gravity; fluid samples
Storage tanks	Temperature and shrinkage
Subsea test tree	Annulus pressure, temperature

Downhole Acquisition	
Downhole recording	DST pressure and temperature, fluid samples retrieved when test string is brought to surface
Surface readout	Downhole pressure and temperature data retrieved by wireline
Wireline tools	Pressure, temperature, flow rates, samples and various other measurements, depending on the suite of tools

^ Data measurement points. Depending on the scale of the test, a variety of measurements may be obtained downhole, at the surface, and at different points along the flowpath. Besides establishing important flow-rate and pressure relationships, the information derived from these measurements helps project engineers track changes in cleanup fluids, understand heat flow and hydrate formation conditions in the system and evaluate performance of system components.



information is vital to predicting the future behavior of a reservoir or well completion.

In its most basic form, a well test records changes in downhole pressure that follow a change in flow rate. Often, downhole pressures and temperatures, surface flow rates and samples of produced fluids are obtained. Variations on this basic theme are carried out with regularity.

To accommodate different testing needs and strategies, service companies have developed a broad array of innovative testing tools and techniques. This article describes advances across a range of downhole and surface testing equipment. We also discuss the reasons for well testing, the strategies applied at different stages in the life of a reservoir, and the answers that can be provided by properly planned, prepared and executed well tests. Examples from a Middle East gas field and a record-breaking operation in the Gulf of Mexico demonstrate the versatility and high performance provided by today's well-testing methods.

Why Test?

Today, most prospects are explored and then produced on the basis of geological and seismic data, logging data, and then well testing data. Prior to drilling a prospect, seismic data initially serve to delineate the depth and breadth of a potential reservoir. During the drilling process, logging data are used to determine static reservoir parameters such as porosity, lithology, rock type, saturation, and formation depth, thickness and dip. Dynamic reservoir properties are measured through well testing. Pressure and rate perturbations induced by the testing process provide important clues to the nature of a reservoir and its fluids.

Wells are tested to determine reservoir parameters that cannot be adequately measured through other techniques, such as mud logging, coring, electrical logging and seismic surveys. Admittedly, in some cases, we can obtain similar measurements through these techniques, but the quality or scope may not be sufficient to meet the operator's objectives. Pressure and temperature measurements, flow rates and fluid samples are keys to understanding and predicting reservoir behavior and production capabilities. Well test data provide inputs for modeling reservoirs, designing well completions, developing field-production strategies and designing production facilities.

Well test results are also crucial for reserves estimations. Many countries require flow testing, with fluids produced to surface, for reserves to be classified as proven. In addition to estimating reserves, these tests provide a means for directly measuring the aggregate response of reservoirs at large scales and for detecting reservoir boundaries.

One of the more important reservoir parameters is permeability. Understanding permeability and its directional variability is essential for developing perforating strategies, evaluating fracture or fault connectivity, predicting well performance and modeling the behavior of the reservoir under primary, secondary or tertiary production. Permeability is a scale-sensitive tensorial property; its value depends on the scale and the direction through which it is measured. And like other reservoir properties, permeability may be heterogeneous. Thus, its characteristics are difficult to scale up from core to reservoir scale, and measurements obtained at one location may not adequately characterize the property at another location within the same reservoir. Well testing, by physically measuring pressures and flow rates, provides a large-scale aggregate measure of permeability. It thereby provides the ultimate means for evaluating a reservoir's ability to transmit fluids.

Well Test Objectives

Productivity Tests
Obtain and analyze representative samples of produced fluids
Measure reservoir pressure and temperature
Determine inflow performance relationship and deliverability
Evaluate completion efficiency
Characterize well damage
Evaluate workover or stimulation treatments

Descriptive Tests
Evaluate reservoir parameters
Characterize reservoir heterogeneities
Assess reservoir extent and geometry
Evaluate hydraulic communication between wells

^ Well test objectives. The objective determines which type of test will be run, and frequently more than one objective must be achieved.

Testing Objectives and Strategies

Well test objectives change with each stage in the life of a well and its reservoir. During the exploration and appraisal phase, well testing helps the E&P company ascertain the size of a reservoir, its permeability and fluid characteristics. This information, along with pressures and production rates, is used to assess the deliverability and commercial viability of a prospect, and is critical for booking reserves. Fluid characteristics are particularly important during the early stages of a prospect's evaluation, when E&P companies need to determine the type of process equipment they must install to treat and move produced fluids from the wellbore to the refinery.

During development, the operator's focus shifts from assessing deliverability and fluid type to evaluating pressure and flow and ascertaining compartmentalization within the reservoir. This information is needed to refine the field development plan and optimize placement of subsequent wells.

During the production phase, well tests are conducted to evaluate completion efficiency and diagnose unexpected changes in production. These tests assist in determining whether production declines are caused by the reservoir or by the completion. Later in the life of the reservoir, these results will prove crucial for assessing subsequent secondary recovery strategies.

Well tests can generally be classified as either productivity or descriptive tests. Productivity tests are carried out to obtain representative samples of reservoir fluids and to determine fluid-flow capacity at specific reservoir static and flowing pressures. On the other hand, E&P companies schedule descriptive tests when they need to estimate a reservoir's size and flow capacity, analyze horizontal and vertical permeability and determine reservoir boundaries (above). Productivity testing typically seeks to obtain stabilized bottomhole pressures over a range of different flow rates. Successive rate changes are made by adjusting choke size, which is not done until continual measurements have determined that bottomhole pressures and temperatures have stabilized.

Unlike testing to obtain stabilized bottomhole measurements, descriptive tests require transient-pressure measurements. Pressure transients are induced by step changes in surface production rates and can be measured by bottomhole pressure sensors or permanent downhole pressure gauges. The changes in production cause pressure perturbations that propagate from the wellbore to the surrounding formation. These pressure pulses are affected by fluids and geological features within the reservoir. While they might travel straight through a homogeneous formation, these pulses may be hindered by low-permeability zones, or may vanish entirely when they enter a gas cap. By recording wellbore pressure response over time, the operator can obtain a pressure curve that is influenced by the geometry of geological features and the particular fluids contained within the reservoir.

Well tests can be carried out before or after a well is completed, and at different stages in the life of reservoir; thus, they come in a variety of sizes and modes (See "The Testing Spectrum," *page 48*). An operator's objectives dictate the mode and scale of the test (next page). Testing modes range from openhole wireline testing with an MDT Modular Formation Dynamics Tester tool to cased hole testing with a CHDT Cased Hole Dynamics Tester tool; or from slickline bottomhole pressure surveys of producing wells to simply monitoring shut-in wellhead pressure.[1]

1. A slickline is a nonelectric cable used for selective placement and retrieval of tools and flow-control equipment in a wellbore. This cable passes through pressure-control equipment mounted on the wellhead, permitting a variety of downhole operations to be conducted safely on live wellbores.

Although some well test objectives are met through extensive tests that run for days or weeks, other test objectives can be accomplished through new techniques in a matter of hours. New developments in technology are radically changing the face of well testing, most notably in the area of flowmetering.

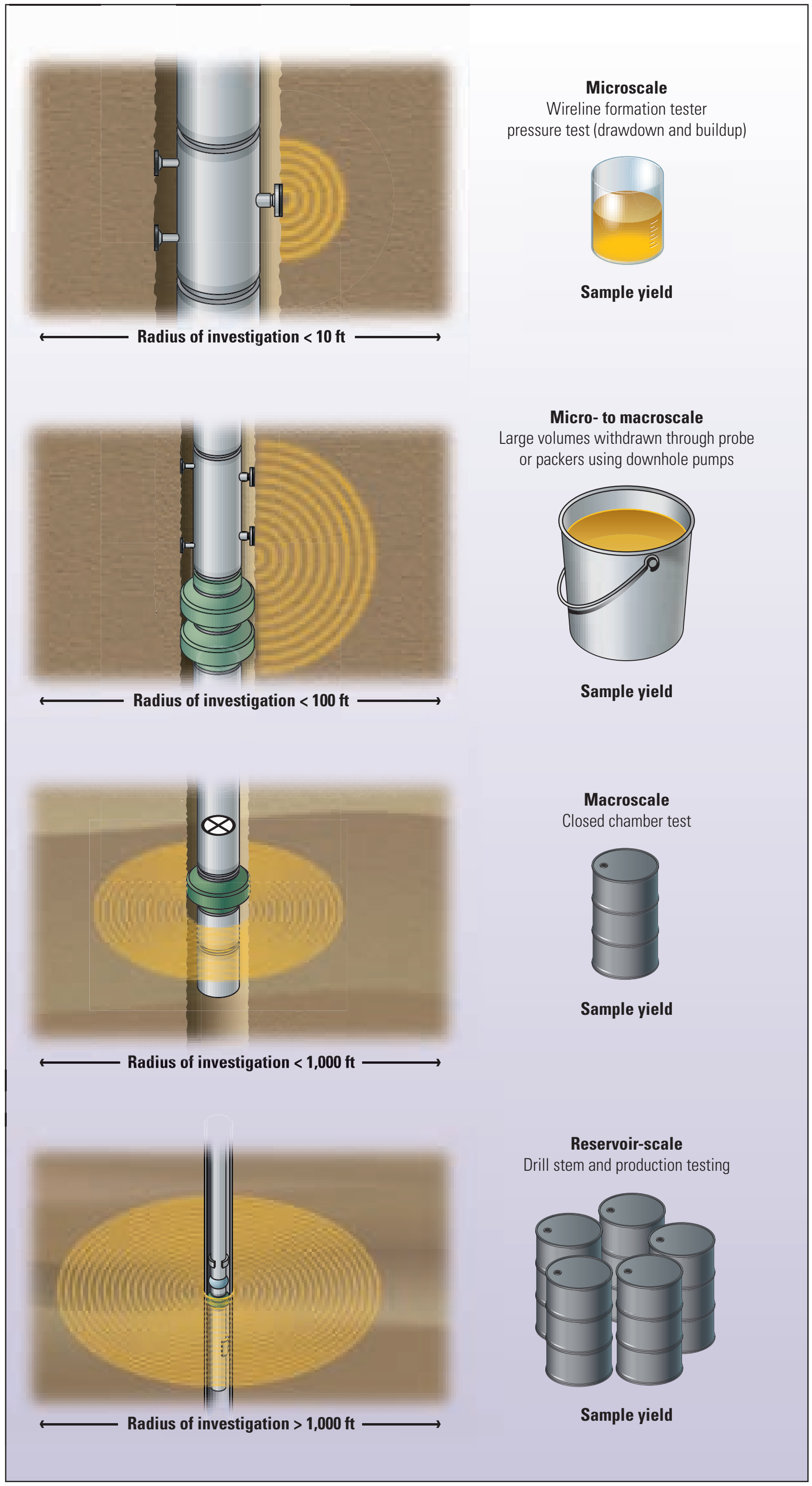
Schlumberger developed its multiphase flowmetering capability over several years and tested it in flow loops and fields around the world. One such early test was conducted with the support of Sonatrach in wells in the Hassi-Messaoud field in Algeria. Results were used to calibrate and verify flowmeter performance before it was commercialized in 2001 as PhaseTester portable multiphase periodic well testing equipment. In 2002, it was delivered to the Hassi-Messaoud field, and has since been utilized in other Sonatrach field operations.

PhaseTester Vx multiphase well testing technology was tested extensively at the In Salah Gas (ISG) project. A joint development project of Sonatrach, Statoil and BP, the ISG comprises the development of seven gas fields in south-central Algeria and represents one of the largest gas projects in the country. Well testing services for the Krechba, Teguentour and Reg fields commenced with the following objectives:

- well cleanup—reduce the potential for formation damage between well completion and its connection to the production facility and reduce facility damage normally caused by solids production during the subsequent startup
- flow deliverability—test the productivity of reentry wells and newly drilled wells
- corrosives—gather information on carbon dioxide [CO_2] and hydrogen sulfide [H_2S] content
- well pressure—acquire downhole pressure data during initial production in each field
- well deliverability—unload the well and conduct a single rate test to determine overall deliverability.

An average flow rate of 50 MMcf/d [1.4 million m^3/d] was expected, so for safety reasons the equipment had to safely handle 70 MMcf/d [2 million m^3/d]. Besides dry gas, the 24-hour production tests were expected to yield up to 9% CO_2, 11 ppm H_2S, and varying amounts of gas condensate, oil, mud, sediment and water. In addition, flowback of diesel used to limit differential pressure against the test string was expected.

(continued on page 52)



^ Test modes and scales. The scale of a test is a function of time. Small-scale tests are carried out by wireline formation tester in a matter of minutes or hours, obtaining fluid samples ranging from cubic centimeters to liters in size, and producing small pressure perturbations that investigate a radius of several feet beyond the wellbore. At the other extreme, extended well tests can last for months, produce several thousand barrels of fluid, and create large pressure perturbations that can propagate for thousands of feet beyond the wellbore.

The Testing Spectrum

The variety of tools and services that fall under the well testing umbrella is extensive. A diverse assortment of tools and techniques has evolved to meet the well testing needs of E&P companies. In this evolutionary sequence, the drillstem test (DST) forms a central trunk from which other testing tools and techniques have grown. The ensuing product sequence followed a natural progression from basic to sophisticated, and branched off to include surface, sampling, slickline and wireline devices.

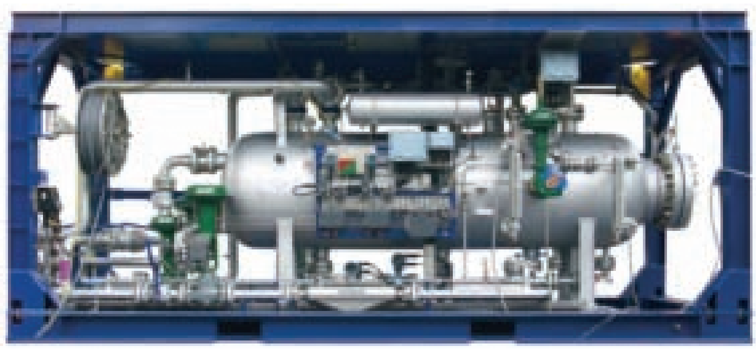
In 1926, brothers E.C. Johnston and M.O. Johnston ran their first commercial DST. This job used a composite packer and valve run in open hole to create a temporary completion and control flow. By 1933, Johnston Well Testers had modified their offering to include a pressure gauge to supplement flow-rate information with formation pressure measurements.[1] Since then, the well testing business has expanded through numerous innovations in equipment and methods.

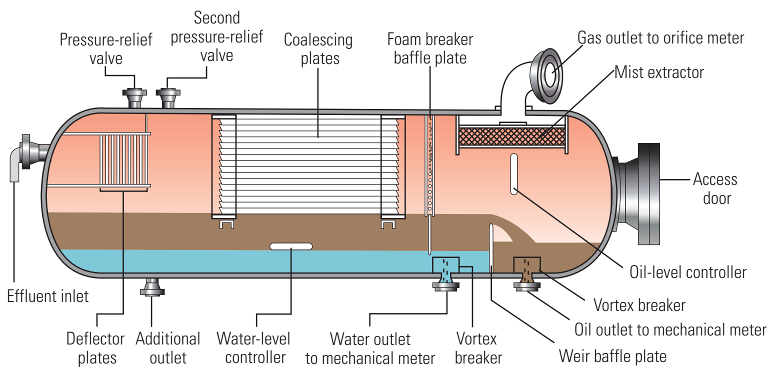
Testing engineers quickly recognized that surface equipment was needed to handle formation fluids produced through the temporary completion established by the DST string. As a result, a three-phase test separator and surge tank became standard equipment in many well testing configurations. The test separator is positioned downstream from the choke manifold, which is used to control flow of produced fluids at the surface.

A separator receives fluids produced from a well and uses gravity and differences in fluid density to separate the fluids into water, oil and gas phases (right). Once separated, the individual phases are metered as they leave the vessel. The gas phase is routed to a separate gas line or is flared.[2] The liquid phases are commingled and returned to a flowline, or sent to a storage tank. In remote locations that cannot accommodate storage and transport of produced liquids, the liquids may have to be routed to a burner for disposal.

A surge tank, placed downstream of the separator, provides a vessel into which separated liquids can flow to neutralize sudden pressure surges. With a decrease in oil pressure at the surge tank, gas will come out of solution, causing a decrease in oil volume. This shrinkage can be measured at the surge tank. Auxiliary equipment may also be required, such as a steam heat exchanger or indirect-fired heater. The heater is placed upstream of the separator to heat produced fluids and prevent hydrate formation, reduce fluid viscosity and break down emulsions. A burner installed downstream of the surge tank disposes of the produced gas and, under certain circumstances, disposes of produced liquids.

Downhole, pressure and temperature measurements can be acquired by slickline. In the past, slickline surveys used mechanical chart recorders to measure downhole pressures, while a maximum-reading thermometer measured bottomhole temperature (BHT). With the advent of crystal-sensor technology, downhole pressure and temperature gauges have grown increasingly reliable and accurate. Even this technology has evolved. A single crystal now measures temperature and pressure at the same point, eliminating temperature lags or other discrepancies seen formerly, when a second crystal was used for thermal corrections. Sensors, such as the CQG Crystal Quartz Gauge sensor and UNIGAGE pressure





^ Test separator. A portable three-phase separator (*top*) is enclosed in a structural framework for protection and lifting support. The cutaway view (*bottom*) shows deflectors and baffles used to separate produced fluids. These fluids enter from the inlet and hit a series of plates, causing liquids to drop out of the flowstream, where they are separated by gravitation based on density contrast.

gauge system, are highly versatile and can record downhole pressure in slickline, DST and tubing-conveyed perforating (TCP) applications. On DST and TCP jobs, measurements are made from either above or below the packer, and gauges can be placed inside or outside the test string. The data are either recorded downhole or transmitted to surface for real-time readout.

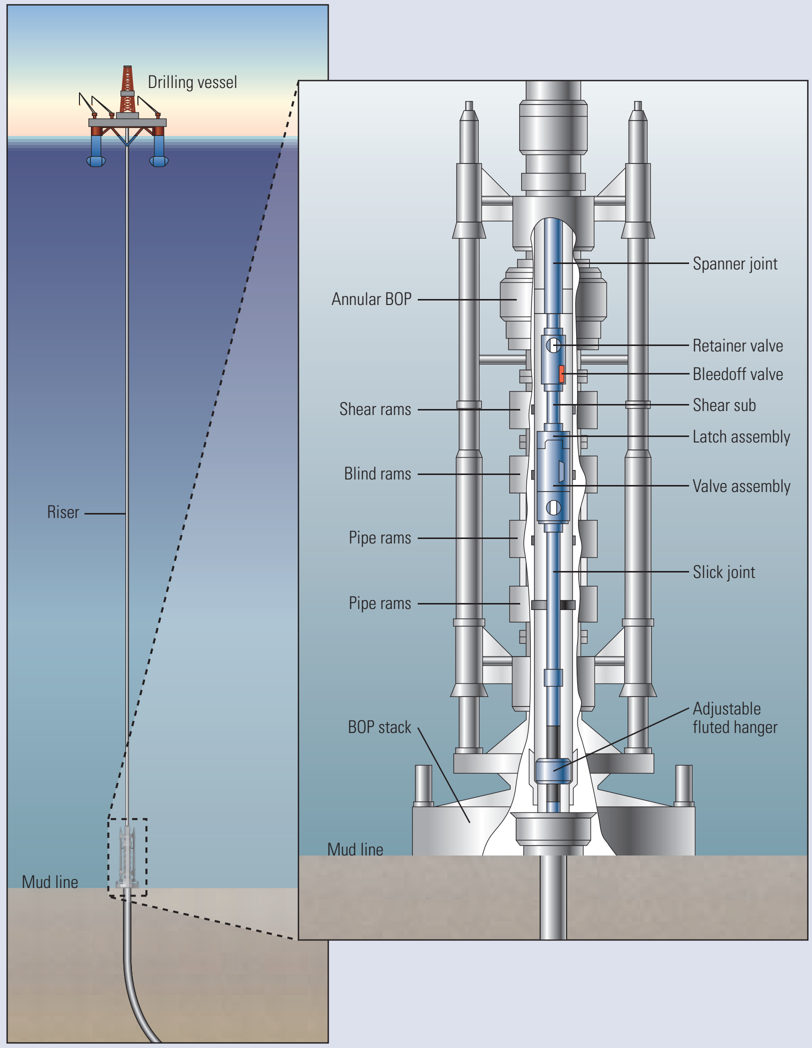
Tester valves, which form the heart of the well test string, have evolved too. From the simple but effective valve of the original Johnston Formation Tester, test tool design progressed to the MFE Multiflow Evaluator reciprocating multicycle tool in 1961. This MFE test tool was utilized on thousands of openhole DSTs and is still in use in traditional DST applications in certain hard-rock areas.

In the 1970s, offshore exploration increased dramatically and with it arose the need for a test valve more suited for cased-hole testing, in much deeper wells and higher pressures and in operations conducted from floating rigs. The PCT Pressure Controlled Tester valve established its niche in this arena, eliminating the need to move the pipe up and down to manually operate the valve—a potential concern when testing from floating rigs. Instead, the PCT tool was operated by applying pressure to the test string-casing annulus. High-rate wells prompted development of the fullbore PCT tool in 1981.

In 1989, the first of a new generation of "smart" test tools was introduced with the development of the IRIS Intelligent Remote Implementation System. This dual-valve system combines the test valve and circulating valve into a single tool. Integral sensors and microprocessors make the tool programmable, providing flexibility in testing operations. The mechanical power to open and close both the test and circulating valves is contained within the tool rather than being supplied from surface through manipulation of the pipe or annular pressure.

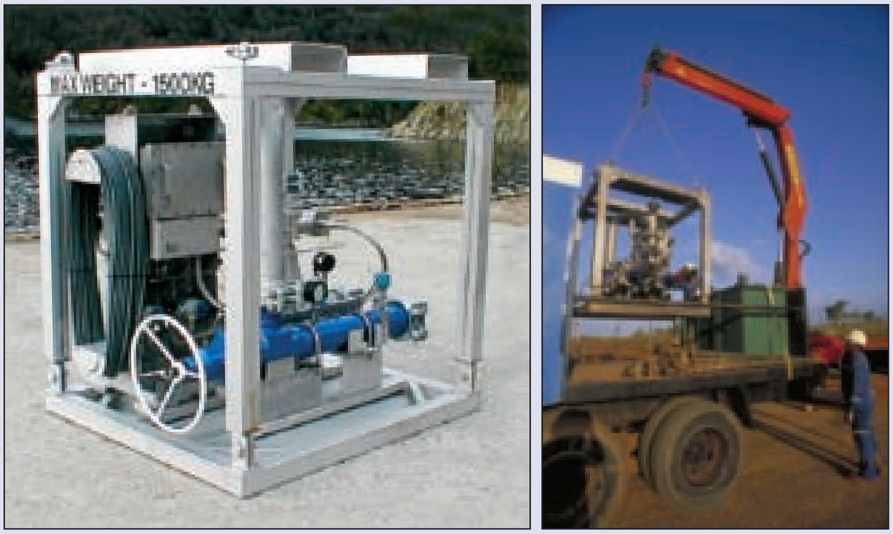
Now, coded pressure pulses sent from surface provide commands to the tool downhole. These low-intensity pressure pulses are transmitted along the annulus and detected downhole by the tool's intelligent controller. The microprocessor analyzes each pulse to differentiate commands from other pressure events during the job. Pulses recognized as IRIS commands are implemented using hydrostatic pressure available downhole to open or close the appropriate valve, or even execute sequenced valve operations. For example, the tester valve can be set to close if annulus overpressure occurs, and can be reopened once the problem has been remedied. The microprocessor stores a pressure-data file and lists all executed commands for postjob analysis of the operation.

Deepwater prospects are drilled and completed by drillships or semisubmersible rigs; well tests conducted from such floating vessels require an additional measure of well control beyond that provided by the drilling blowout preventer (BOP). This requirement spawned the development of the Johnston-Schlumberger E-Z Tree retrievable well control system in 1975. In 1997, another system was developed to provide greater security during urgent situations, allowing closure of pipe and shear rams with the test tree in place. The SenTREE subsea well control system provides hydraulic control from the surface to a dual fail-safe ball and flapper valve module (above). The SenTREE



^ Subsea test tree. The SenTREE test tree was designed to enhance well control during well tests conducted from drillships and semisubmersibles. It is landed inside the BOP stack at the seafloor.

1. Johnston Well Testers was acquired by Schlumberger in 1956.
2. Atkinson I, Theuveny B, Berard M, Connort G, Lowe T, McDiarmid A, Mehdizadeh P, Pinguet B, Smith G and Williamson KJ: "A New Horizon in Multiphase Flow Measurement," *Oilfield Review* 16, no.4 (Winter 2004/2005): 52–63.



^ Portable flowmeter. The PhaseTester multiphase flowmeter is housed in a modular framework (*left*). At 3,750 lbm [1,705 kg], the PhaseTester flowmeter is compact enough to be transported by a mid-sized truck (*right*).

system also serves as a disconnect point for the test string in the event that the rig position moves out of tolerance, forcing the rig to move off the subsea BOP.

At the surface, a new approach to multiphase measurement has taken place. PhaseTester portable multiphase periodic well testing equipment was developed to accurately measure flow rates of oil, gas and water phases without the need to separate the flowstream into individual phases. The device can accurately measure each phase in slug flows, foams and stable emulsions.[3] This flowmeter is typically installed immediately downstream of the wellhead and upstream of the surface separator during DSTs (above).

Using Vx multiphase well testing technology developed by Framo Engineering AS and Schlumberger, the PhaseTester unit combines a venturi with a dual-energy-gamma ray, high-speed detection system. Pressure is measured as the fluid enters the constriction in the venturi throat. A small radioactive chemical source on one side of the venturi emits gamma rays across a discrete range of energy levels, and the attenuation of gamma rays caused by the fluid is measured at two different levels. Across from the source, a scintillation detector combined with a photomultiplier detects gamma rays that have not been absorbed by the fluid mixture as it flows through the venturi. Taking these measurements 45 times per second ensures accurate measurements regardless of turbulence in flow regimes.

The low-energy gamma ray count rate is related to the composition of the fluid—thereby responding to the water/liquid ratio. The high-energy count rate is primarily related to the density of the mixture. A flow computer determines relative fractions of each phase present in the pipe. The combination of mixture density and pressure differential across the venturi delivers a robust and high-resolution total mass flow rate. The flow computer combines PVT volumetric properties of the fluid with the fractions and the mass rate to deliver instantaneous volumetric rates of oil, gas and water every 10 seconds.

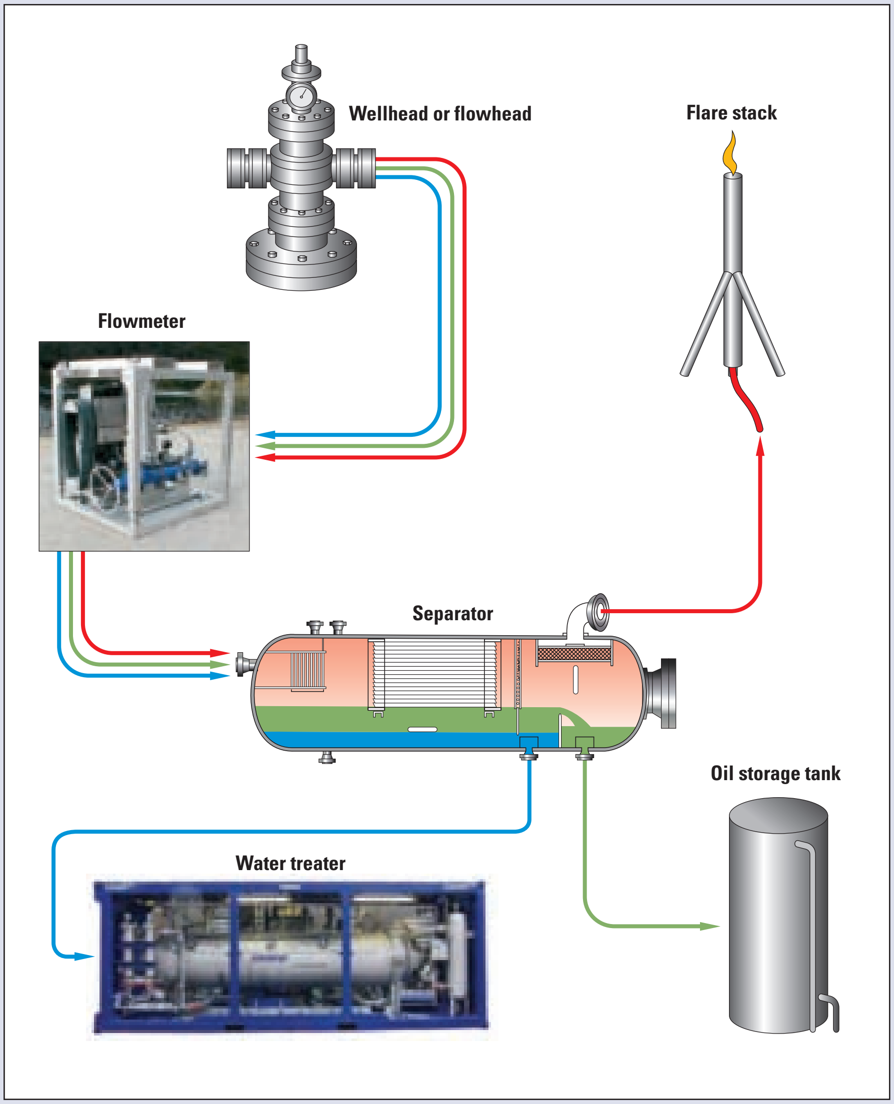
A special Vx interpretation program has also been developed for measuring flow in gas wells with gas volume fractions (GVF) ranging from 90% to 100%. The Vx gas-mode interpretation program enables the PhaseTester flowmeter to measure gas flow rates across the full spectrum of gases, from dry gas to extremely wet gas and gas rich in condensate. With GVF flows as high as 98%, the Vx gas-mode program can also achieve accurate measurement of water flow rates.

Some of the concepts described above have been integrated into a compact, lightweight well testing package for acquiring accurate flow-rate data while processing large volumes of well effluent produced during testing. The CleanTest well testing service uses a multiphase flowmeter, a specially designed surface separator, a water treatment unit placed downstream of the separator, and if needed, a high-efficiency burner for smoke-free disposal of effluent (next page).

The PhaseTester Vx flowmeter, located on the surface between the wellhead and the separator, continuously monitors produced fluids during the well test, eliminating dependency on the separation process for flow measurements. This is especially important during the cleanup period, when the well is initially opened up to flow and the invaded zone of the formation unloads mud filtrates, brines and other fluids pumped downhole during drilling or completion processes. Using the multiphase flowmeter to monitor flow rates at the surface, the operator can immediately determine the instant that the well has cleaned up.

On the CleanTest platform, a CleanSep adjustable well test separator is placed downstream of the flowmeter to manage effluents. By installing the highly accurate PhaseTester flowmeter upstream, the separator is relieved of instrumentation normally used to measure phase fractions at the surface. This allows the separator to be put on line the moment the well is opened up for flowback; the flowstream is no longer rerouted to bypass the separator during the cleanup period to avoid damaging the instrumentation. This approach saves rig time on testing programs that typically require two to three days of progressive choke adjustments before cleanup is sufficient to permit produced fluids to be routed through the separator.

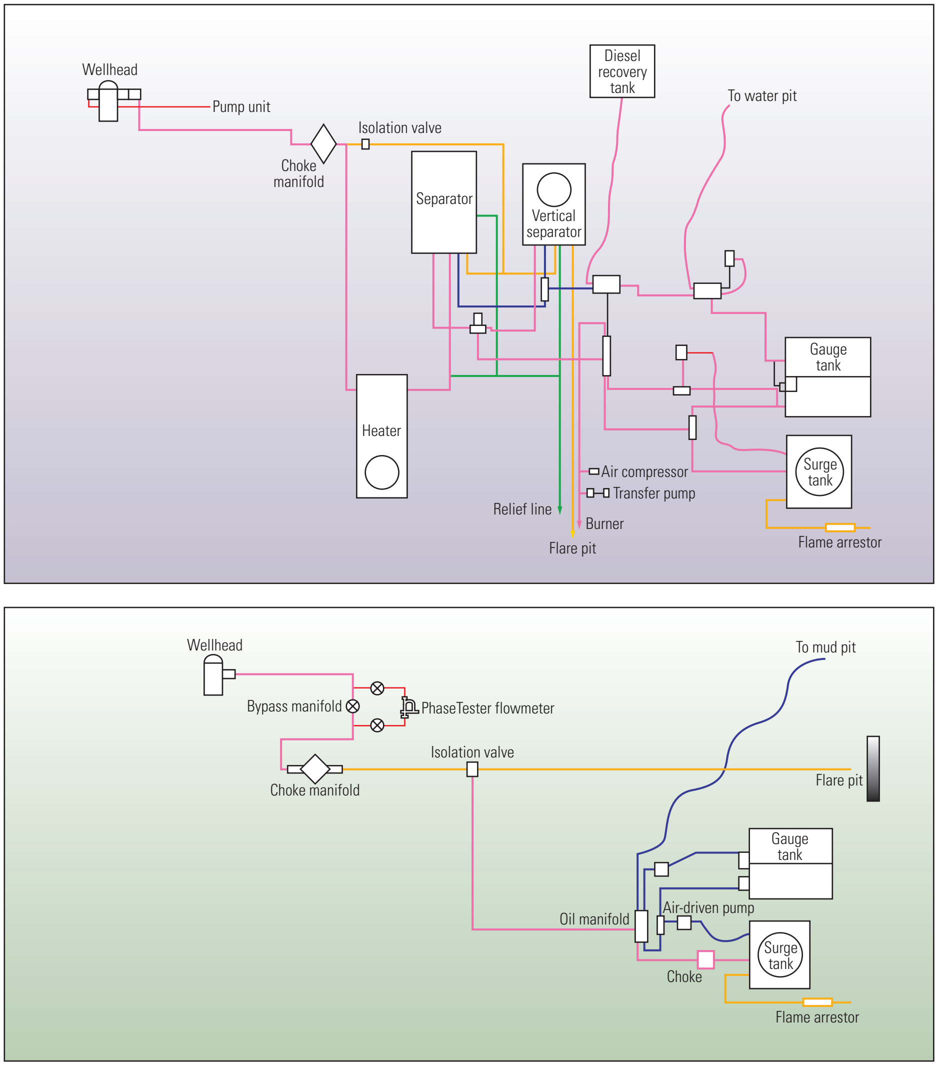
3. Atkinson et al, reference 2.



^ Flowstream schematic. Reservoir fluids are handled by the CleanTest platform. Fluids produced to surface are metered through the PhaseTester multiphase flowmeter before being sent downstream to a specially designed separator. By monitoring the flowmeter, the operator can fine-tune flow and heat adjustments at the separator, thereby optimizing fluid-handling performance. Water exiting the separator passes through a treatment unit to remove remaining oil prior to discharge. High-efficiency burners dispose of any fluids that the operator is not equipped to store or transport.

The separator uses a remotely controlled weir that moves up or down with fluctuations in oil- and water-phase fractions. Inside the separator, gas, oil and water phases of the production stream are split into their respective fractions before being discharged.

Water exiting the separator is sent to a mobile water treatment unit. This unit combines coalescing and gravity separation techniques to reduce oil-in-water concentrations. For instance, water that enters the unit with 20,000 ppm of dispersed oil will contain less than 20 ppm of oil at the outlet, even with dense, low API-gravity oils. The oil-in-water content is confirmed when samples taken at the unit are run through an onsite analyzer. By removing oil from the water, the unit assists in compliance with strict environmental discharge regulations that allow water disposal directly into the sea. Such compliance provides the operator with a cost-effective alternative to water storage, transport and disposal. The oil is gathered into an atmospheric oil recovery chamber, and a built-in pump is provided to export the recovered oil to a storage tank or to the burner.



^ Simplified layout. A comparison of the original test setup (*top*) and a later well test layout (*bottom*) shows a dramatic reduction in piping and complexity obtained by including the PhaseTester multiphase flowmeter.

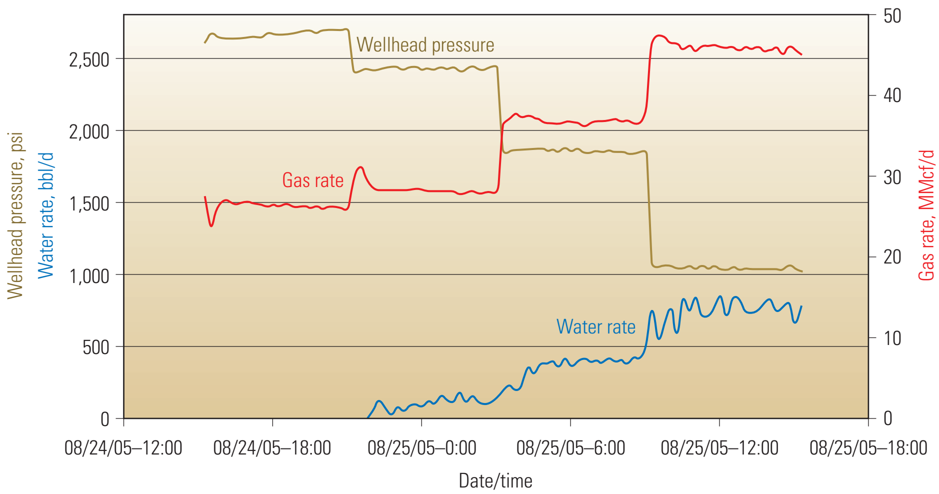
Originally, the project relied on conventional technology such as horizontal gravity separators, surge tanks, manifolds, transfer pumps and burners. In 2004, Schlumberger introduced the PhaseTester Vx gas-mode interpretation model. The multiphase capabilities of the gas-mode interpretation model extended the full range of flow measurements to wet- or dry-gas conditions. The PhaseTester multiphase flowmeter also provided accurate readings of gas flow rate at standard conditions, and obtained liquid rate and water-cut values.

The PhaseTester flowmeter dramatically simplified the field setup because phase separation was no longer needed and sampling was not a critical objective (above). This new layout proved inherently safer than previous well tests. Rig-up and rig-down times were also faster by an average of 11.5 days. The need for personnel, trucks and support vehicles was greatly reduced, resulting in an estimated cost savings of 28% compared with previous well tests.

In another well test, the operator was concerned about the ability to resolve uncertainties in liquid-phase production. During the Krechba field campaign in 2005, the PhaseTester Vx system was able to clearly delineate the gas and liquid flow rates (next page, top right). These rates were subsequently confirmed using the PLT Production Logging Tool. Using the PhaseTester Vx technology, the operator obtained high-quality data while increasing safety and reducing cost related to logistics, personnel and operating time.

Fluid Sampling

Beyond pressure, temperature and flow rate, the operator also needs to know the precise nature of the fluids produced by the reservoir. The future of a prospect hinges on the operator's understanding of the fluids contained within a reservoir (next page, bottom right). Important economic considerations such as reservoir recovery factor, reserves estimates and production forecasts are affected by fluid properties. In addition to obtaining information about chemical composition, density, viscosity and gas/oil ratio (GOR) of the fluid, operators are especially interested in determining the conditions under which the produced fluids will form waxes, hydrates and asphaltenes. Knowledge of fluid properties is therefore essential to evaluating the profitability of a well or prospect.



^ Fluid determination during well test cleanup. This Krechba field well was monitored by the PhaseTester flowmeter over a 24-hour cleanup period. Following each increase in choke size prescribed by the cleanup program, wellhead pressure, liquid and gas rates were measured. PhaseTester results show distinctive plateaus for each phase, corresponding to adjustments in choke size.

Well testing offers a prime opportunity to collect representative reservoir-fluid samples. Samples are considered representative of fluids in the reservoir when they are single-phase, and have been collected at saturation-pressure and critical-temperature conditions above which organic solids would precipitate from the sample. The pressure-temperature criteria must be strictly observed for samples to be representative.

Analyses of representative samples are vital inputs for the design and simulation of production processes that take place between the sandface and the sales pipelines. These simulations rely on pressure-volume-temperature (PVT) analysis data, and start with the assumption that a reservoir is performing under initial conditions, before the reservoir is produced. Once produced, its fluid properties inevitably change as pressures decrease over the life of a reservoir.

It is not always possible to obtain a representative sample of the original reservoir fluid. When reservoir pressure drops below the bubblepoint pressure of the oil, lighter fractions of the oil will vaporize into a separate gas phase.[2] The opposite effect is seen when pressure in a gas condensate reservoir drops below the dewpoint pressure.[3] Liquid will form as the gas condenses. The compositions of these reservoir fluids will then be altered by the corresponding loss of light or heavy fractions.

Timing is critical in obtaining a representative sample of the original reservoir fluid. Samples should be taken as early as possible in a reservoir's producing life to avoid the two-phase condition caused by pressure drawdown as the well is produced. For this reason, discovery wells are often sampled extensively, using wireline formation testers after an interval is drilled, and again during the drillstem test (DST).

In addition to pressure, an operator must consider how representative a sample can be if it is drawn from a reservoir of large areal extent. That is, a single sample from a given position may not account for variations or compartmentalization within an expansive reservoir. Neither would a single sample account for fluid gradations that are seen between the top and bottom of massive pay sections. Therefore, reservoir fluids are often sampled as other wells are drilled across a reservoir. Samples are also taken from different depths in the reservoir, typically using a wireline formation tester.

Fluids sampled at the surface can differ greatly from fluids sampled downhole. Asphaltenes may precipitate out of reservoir fluids with the drop in pressure that occurs as fluids are produced from the perforation to the surface. Waxes can also precipitate out of solution with a drop in temperature that accompanies fluids as they are produced to the surface. The difference between downhole and surface fluid properties is of keen interest to an operator, and a variety of techniques has been developed to capture each type of sample.

Surface samples are collected at the wellhead or at the separator. Separator samples require individual samples of the oil and gas phases to be taken, along with accurate measurements of their respective flow rates, pressures and temperatures. The oil and gas samples are later combined in a laboratory to form a representative sample. These samples are taken when special analysis requires volumes that exceed the capacity of conventional sampling tools or when it is not possible to collect reservoir fluid samples downhole. Such volumes may be required for analyses used in refinery studies or enhanced oil recovery studies.

Who Needs Fluid Samples?

Completion and Production Engineers
Completion designs
Material specifications
Artificial lift calculations
Production log interpretations
Production forecasts

Geologists
Reservoir correlations
Geochemical studies
Hydrocarbon source studies

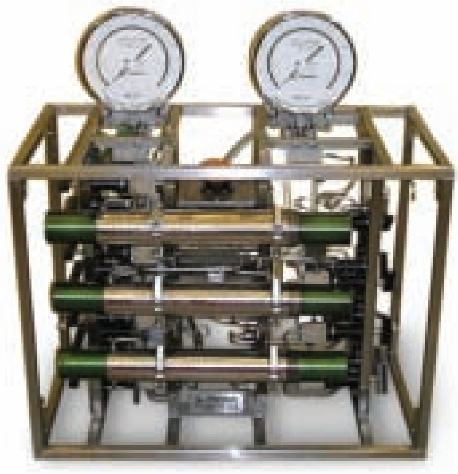
Reservoir Engineers
Well test interpretations
Reserves estimations
Material balance calculations
Natural drive mechanism analysis
Reservoir simulations

Facilities Engineers
Flow assurance mitigation
Separation and treatment of produced fluids
Metering options
Transport strategies

^ Demand for produced fluid samples. Representative fluid samples and their analyses are required upstream and downstream of the wellhead.

2. The bubblepoint is the temperature and pressure at which part of a liquid begins to convert to gas. Thus, if a constant volume of liquid is held at a constant temperature while pressure is decreased, the point at which gas begins to form is the bubblepoint.

3. The dewpoint is the temperature and pressure at which a gas begins to condense. If a constant pressure is held on a given volume of gas while the temperature is gradually reduced, the point at which droplets of liquid begin to form is the dewpoint of the gas at that pressure.



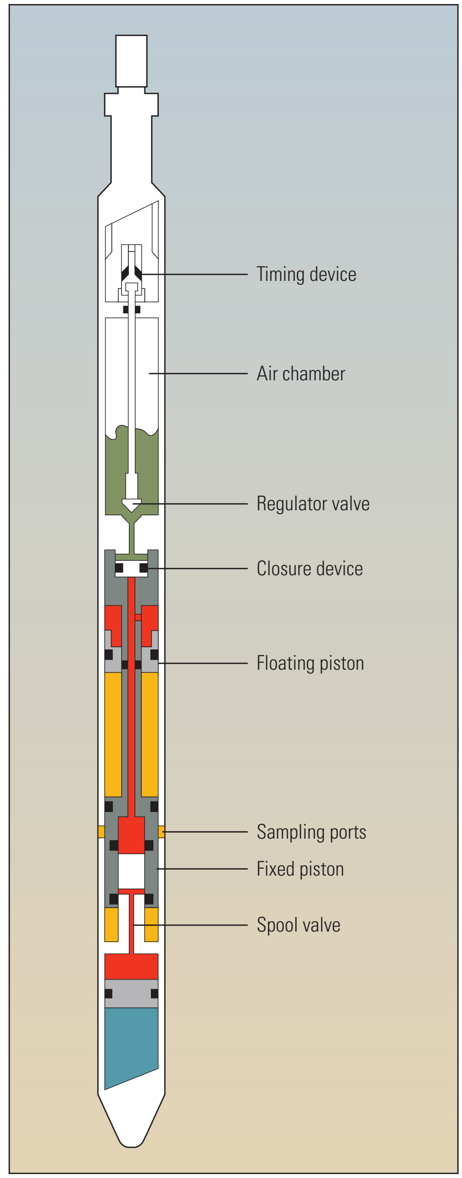
^ Wellhead sampling manifold. This easily transportable unit provides sampling cylinders, valves and necessary gauges for capturing produced fluids at the wellhead.

Downhole samples, commonly referred to as bottomhole samples, are the most representative of the original formation fluid, because they are collected as close to reservoir pressure and temperature as wellbore conditions permit. Bottomhole samples are taken from devices deployed on wireline or slickline, or as an integral part of the DST toolstring. They are used when the flowing bottomhole pressure is greater than the reservoir oil-saturation pressure. Bottomhole samples are essential for PVT analysis and for evaluating potential flow-assurance problems, such as the precipitation and deposition of asphaltenes and waxes.

Several factors influence the choice of sampling technique: reservoir properties, the volume of sample required, the type of reservoir fluid to be sampled, the degree of reservoir depletion, and the type of surface and subsurface equipment required. Each sampling mode requires its own special equipment, though certain components are common to most. The range of sampling modes can be loosely grouped into five basic techniques:

- Wellhead sampling: A purpose-built wellhead sampling manifold is used to collect samples at the surface (above). These samples can be collected only when the flowing wellhead pressure and temperature are above the reservoir fluid-saturation pressure, such that the fluid is a single phase at the wellhead. Such conditions are not typical, but are sometimes present; for example, in certain subsea wells where produced fluids may remain in single phase all the way to the surface choke manifold.
- DST surface sampling: Samples of oil and gas are often acquired at the test separator. With accurate measurements of oil and gas flow rates, pressures and temperatures, these samples can be recombined in a laboratory to approximate the composition of a representative fluid at depth. Such samples require stable flow conditions inside the separator. Surface samples should always be collected as a precaution against unforeseen problems that could prevent successful retrieval of downhole samples.
- DST downhole sampling: Representative fluid samples are taken downhole at the end of the DST main flow period. Commands from surface are transmitted to open a sample chamber, such as a single-phase reservoir sampler (SRS), which is incorporated into a special drill collar on the DST string. (right). Using a SCAR downhole carrier, up to eight SRS single-phase samples can be obtained. The SCAR sampling tool is activated by rupture disk or by mud-pulse telemetry to an IRIS trigger. DST bottomhole sampling takes place at reservoir pressure and temperature, such that single-phase fluid is recovered if reservoir pressure is above the bubblepoint.
- Slickline sampling: Typically run in producing wells, SRS sample devices can be suspended on a slickline and lowered through the production tubing to the top of perforations. A timer on the SRS allows the sample chamber to open and admit fluids after sufficient time has passed for the tool to reach the desired depth.
- Wireline formation tester sampling: Wireline tools such as the MDT tool are routinely run in open hole to measure reservoir pressures, and frequently measure pressures at several depths spanning the reservoir to obtain a reservoir pressure gradient, in addition to collecting reservoir fluid samples. The multisampling capability of the MDT tool means that it can collect samples from various depths across a reservoir to delineate complex gradations in the fluid column. Wireline formation tester results are often used to guide subsequent drillstem testing.

Inside the MDT tool, sample quality is monitored by an OFA Optical Fluid Analyzer, LFA Live Fluid Analyzer or CFA Composition Fluid Analyzer modules. These modules can determine if a fluid has passed through its saturation pressure—as when an oil sample drops below its bubblepoint, or a gas sample drops below its dewpoint. They also verify that the sampled fluid is sufficiently low in filtrate contamination.[4]



^ Downhole fluid sampler. The single-phase reservoir sampler (SRS) uses a nitrogen-charged piston to exert pressure on the 600-cm^3 fluid-sample chamber, thereby keeping the fluid above its saturation pressure and in single phase when the sample chamber is brought to surface. Maintaining high pressure also prevents the fluid from precipitating asphaltenes, which can make samples unrepresentative.

Samples acquired by MDT tool are stored in a single-phase multisample chamber (SPMC) to ensure that the fluids are maintained at formation pressure as they are brought to surface. In exploration wells, openhole MDT samples often serve as a preliminary indicator of reservoir fluid type before the cased-hole well test is conducted. In some wells, MDT pressure measurements and sampling are run in lieu of the DST.

For oil-base muds (OBM), a special focused sampling system has been developed to reduce contamination of the hydrocarbon fluid sample by miscible oil-base drilling fluid filtrate. The Quicksilver Probe wireline sampling tool uses two distinct flow areas to focus clean formation fluid into the MDT tool.[5] A perimeter, or "guard" ring around the outside of the probe captures filtrate, while a central ring draws in clean reservoir fluid from the center of the cone of flow. This tool is not restricted to OBM though; the same guard probe provides faster, cleaner sampling in wells drilled with any type of mud.

Downhole sampling can also be performed in cased hole, using the CHDT tool, a variant on the MDT tool. This tester drills a 0.28-in. diameter hole through casing, cement and formation, then inserts a probe to take pressure measurements and samples. After the probe is withdrawn, a 10,000-psi [69-MPa] bidirectional seal is inserted to plug the casing hole.[6]

^ Portable fluid analysis laboratory. The PVT Express mobile analysis service can provide information about the physical characteristics, composition and behavior of reservoir fluids. By bringing the laboratory to the wellsite, the operator can quickly obtain a detailed analysis of fluid composition, bubblepoint or dewpoint pressures, compressibility, viscosity and other important parameters.

Fluid Analysis

Pressure-volume-temperature (PVT) relationships and composition of produced fluids are of great interest to E&P companies, and are essential for evaluating the profitability of a well or prospect. The composition and physical properties of produced fluids impact critical completion designs, and those of the flowline, separation and pumping stations, and even processing and refining plants—especially when CO_2, H_2S or other corrosives are produced. Compositional analysis provides key input for reservoir simulation.

Fluid analysis is carried out in PVT laboratories, some of which can be brought to the wellsite. The PVT Express onsite well fluid analysis service delivers a dedicated PVT analysis laboratory to the wellsite (above right). Experts from Oilphase-DBR fluid sampling and analysis service conduct PVT analyses as soon as the samples are collected. In their self-contained laboratory, PVT analysts measure saturation pressure, bubblepoint and dewpoint, GOR, gas composition to C_{12} and liquid composition to C_{36}, atmospheric liquid density and viscosity.[7] Customized fluid analysis results are delivered to the client within hours, enabling critical testing and completion decisions to be made.

In a recent offshore well test, PVT Express specialists analyzed reservoir fluid samples collected at the wellhead, along with separator gas and liquid samples. The Oilphase-DBR engineer measured the wellhead fluid sample saturation pressure at the sampling temperature and at reservoir fluid temperature, and the fluid gas/oil ratio, and composition. This information was transferred to the InterAct real-time monitoring and data delivery system and transmitted to the Oilphase-DBR Houston Fluid Analysis Center, where data quality checks were carried out. The results were then loaded into PVT Pro equation-of-state simulation software for further modeling. The resulting pressure-temperature matrix was sent back to the rig, where it was downloaded into a PhaseTester data file. The data enabled test engineers to create a customized fluid identification for optimizing PhaseTester flowmeter measurements obtained during the well test.

Well Test Planning

With the advent of computerized planning applications, well testing by generalized rules has gone the way of the nomogram. Well tests require clearly defined objectives and careful planning. Most well tests are designed around objectives such as taking fluid samples for laboratory analyses, measuring reservoir pressure and temperature, determining well productivity, evaluating completion efficiency or determining reservoir size, boundaries and other parameters. To achieve these objectives, the test engineer must devise a dynamic measurement sequence and select the right hardware to do the job.

4. Andrews RJ, Beck G, Castelijns K, Chen A, Cribbs ME, Fadnes FH, Irvine-Fortescue J, Williams S, Hashem M, Jamaluddin A, Kurkjian A, Sass B, Mullins OC, Rylander E and Van Dusen A: "Quantifying Contamination Using Color of Crude and Condensate," *Oilfield Review* 13, no. 3 (Autumn 2001): 24–43.

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5. For more on the Quicksilver Probe sampling tool: Akkurt R, Bowcock M, Davies J, Del Campo C, Hill B, Joshi S, Kundu D, Kumar S, O'Keefe M, Samir M, Tarvin J, Weinheber P, Williams S and Zeybek M: "Focusing on Downhole Fluid Sampling and Analysis," *Oilfield Review* 18, no.4 (Winter 2006/2007): 4–19.
6. Burgess K, Fields T, Harrigan E, Golich GM, MacDougall T, Reeves R, Smith S, Thornsberry K, Ritchie B, Rivero R and Siegfried R: "Formation Testing and Sampling Through Casing," *Oilfield Review* 14, no. 1 (Spring 2002): 46–57.
7. Oilphase-DBR is the fluid-sampling and analysis division of Schlumberger. Oilphase was founded in Aberdeen in 1989 with the launch of the industry's first single-phase, cased-hole, bottomhole sampling tool. Oilphase was acquired by Schlumberger in 1996. DBR was founded in 1980 in Edmonton, Alberta, Canada, by Donald Baker Robinson, the coauthor of the Peng-Robinson equation of state. DBR designed and manufactured mercury-free PVT and flow assurance laboratory equipment, equation-of-state software, and heavy-oil fluid analysis services. In 2002, DBR was acquired by Schlumberger and merged with Oilphase.

Whatever the operator's objectives, all well tests today are designed with safety and environmental protection as top priorities.

The first step in effective test design involves a detailed understanding of the proposed well test objectives. All decisions about rate handling, test period durations, pressure gauge sampling frequency, and fluid sampling protocol require a firm understanding of what the test is expected to prove. In some cases, sample collection is a priority; some require maximum rate or drawdown; and others seek to evaluate completion efficiency or investigate reservoir boundaries. For each objective, a careful and deliberate analysis of costs versus benefits must be carried out.

Test objectives are developed after a detailed analysis of geophysical, petrophysical and drilling information. These objectives should then be prioritized to aid subsequent decision-making when economic and operational factors must be considered. From this analysis, geologists and engineers will determine which zones to test, the type of test data they need to acquire to satisfy the stated objectives, and hence the type of well test they need to run.

To determine the range of objectives that can be met by a well test, test engineers model the reservoir's response to changes in production rate during the test. Computerized simulations allow well test designers to weigh the effects of a wide range of pressures and flow rates on the reservoir and the testing system. Simulation also helps identify the types of systems capable of measuring the expected pressure, temperature and rate ranges as well as the downhole and surface test equipment that will be required to physically execute the well test program.

Simulation results are reviewed to determine when key pressure-transient features will appear, such as the end of wellbore storage or completions effects, or the start and duration of infinite-acting radial flow.[8] These results also let test personnel anticipate the emergence of outer-boundary effects caused by faults or pressure boundaries. Sensitivity analyses determine the effects of potential reservoir parameters on the duration of flow and shut-in periods. At this point, a review of the prioritized well test objectives may be necessary. It is not uncommon to find that the flow or shut-in time required to achieve a particular objective is prohibitive in light of the associated cost. Such trade-offs are a very real part of the well test planning process.

With testing parameters in hand, well test engineers can select data-acquisition systems and well test equipment appropriate to the job. Important considerations include the following:
- ensuring that required well test data will be sufficient to validate the test
- requiring surface readouts to display pressure and temperature data measurements for real-time decision-making versus downhole recorders
- using high-resolution gauges when test objectives call for detailed reservoir description
- ensuring redundancy of measurements
- requiring redundancy of downhole tools throughout operations in offshore wells to ensure positive well control downhole and at the seafloor
- selecting surface equipment to safely and efficiently handle expected rates and pressures
- disposing of produced fluids in an environmentally sound manner.

The design and specification of surface flow equipment are quite involved. To safely produce fluids to surface, well test engineers must design a system that can withstand and control high-rate flows of liquids and gases from the flowhead to the separator to the storage tanks, or on through to the flare stack. To prevent potentially disastrous erosion of piping, bends and equipment, they must factor in fluid velocity, drag and pressure drops from one component to the next.

An important planning tool is the equipment layout diagram. This schematic shows the testing equipment to be used, the general piping layout, and the specific location of each piece of equipment at the wellsite. With expected flow rates and wellhead pressures in mind, well test designers can determine the size and pressure ratings for the piping, flowhead, choke manifold, heater and test separator. Correct piping size, in particular, is important in preventing excessive fluid velocities, large pressure losses and overpressurization of equipment.

High flow rates are a particular concern with respect to the surface test separator. Too much fluid can quickly overwhelm the equipment, causing liquid carryover into the separator gas line, or formation of foam in its oil line. By designing a system with retention times and pressure profiles in mind, well test engineers can avoid such problems.[9] Their test design must also ensure maintenance of a temperature and pressure regime that will prevent the formation of hydrates, or else they must plan to inject glycol or methanol upstream of the choke manifold.

The test design considers safety from one end of the system to the other. All surface testing equipment must be grounded. Piping, flowlines and vent lines are color-coded to identify the working pressure of the pipe, and each must be anchored. The layout is also designed to accommodate or counter the effects of noise and heat. Noise measurements obtained during well tests show a corresponding rise in decibels at the separator and gas line as flow rates increase. Heat is a concern for personnel and equipment, so the equipment layout plan must provide for appropriate isolation distances between various pieces of equipment, such as the wellhead, steam exchanger, separator or flare stack. These distances are dictated by industry standard classifications assigned to each component to reduce the likelihood of accidental combustion.

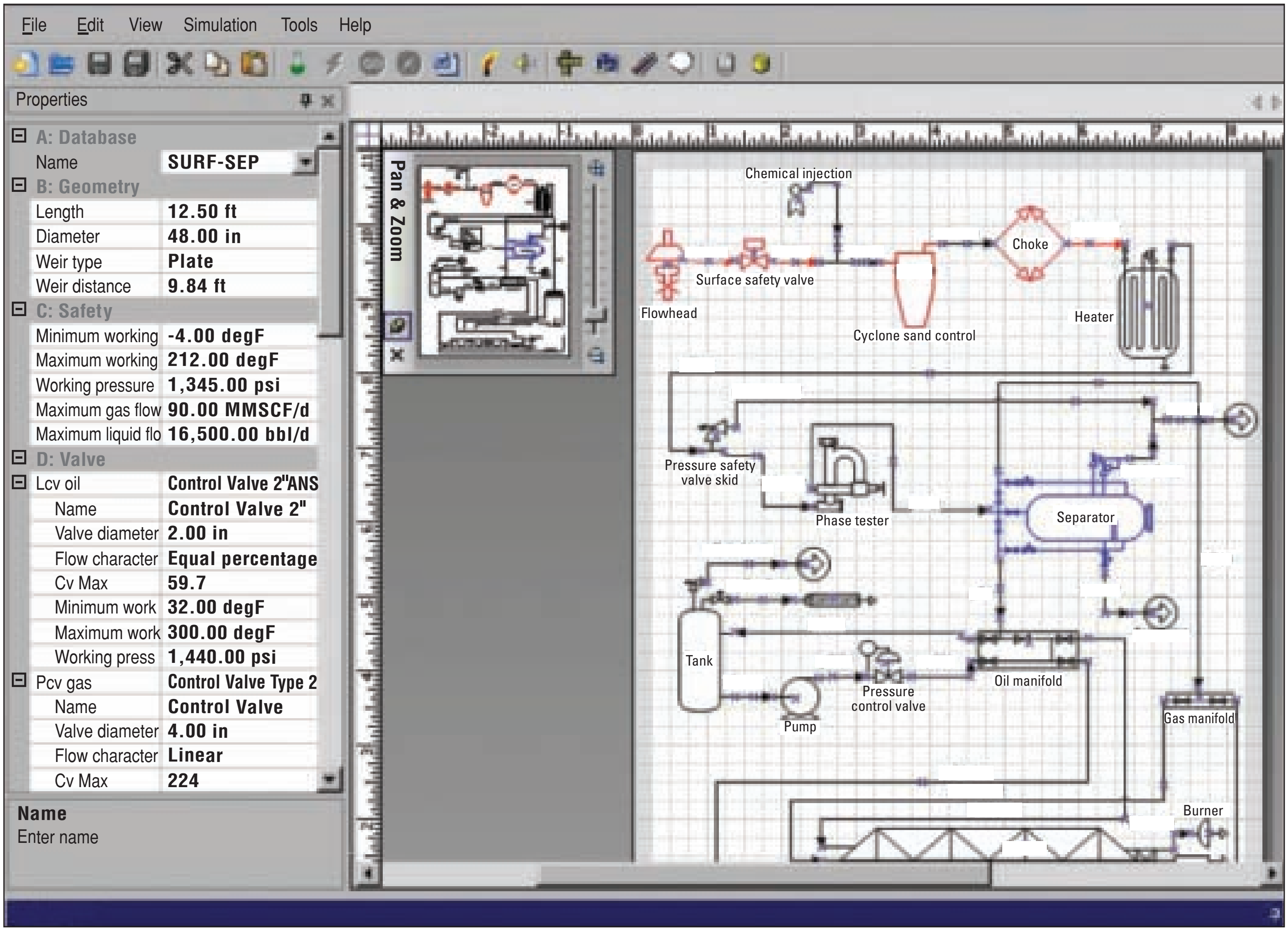
Well test design software can be useful for specifying surface equipment and mapping its layout. ArchiTest well test design software works with PIPESIM production system analysis software to carry out a nodal analysis of the surface system, creating a realistic steady-state simulation of surface processes. This application accounts for the surface inventory of well testing equipment—from choke to separator to burner (next page). With inputs such as wellhead flow pressure, temperature, flow rate, fluid composition, API gravity of oil, and specific gravity of gas, this software can model fluids as they are produced through the surface equipment—beginning with drilling or completion fluids and transitioning to reservoir fluids.

The output predicts pressures and flow rates over time and highlights equipment that is not rated for anticipated conditions. The system can then be used to determine system sensitivity to changes in variables ranging from separator pressure to surface choke or flowline size. This software is also used to determine erosion at different velocities and to calculate retention times required to process fluids through the separator.

If the well is not connected to production facilities and the client requires disposal of produced fluids, ArchiTest software can predict the noise and heat radiation patterns emanating from the flare. The software can also anticipate hydrate, emulsion or foaming risks.

8. As a pressure transient diffuses into a formation, it is no longer affected by wellbore and near-wellbore effects, and becomes more indicative of formation properties. This period is often called the infinite-acting radial-flow regime because the transient is unaffected by external boundaries and thus acts as if it is infinite in areal extent.

9. The rate at which a fluid passes through a component is a function of its retention time.



^ Automated layout schematic. The ArchiTest program assists in designing the layout for surface test equipment. Length, diameter and working pressures of each component in the layout are checked against calculated flow rates, pressure drops and erosion rates to ensure that the equipment is capable of handling produced fluids. Surface test components that are insufficiently rated for the job are highlighted in red for easy identification.

Well test planning, high-performance equipment and attention to safety and environmental requirements are put to their most challenging test in the deepwater environment. A recent well test highlights some of the complexities involved in planning and implementing an extended well test.

Deepwater Extended Test

In the Gulf of Mexico (GOM), 99% of proven oil reserves are produced from rock of Miocene age or younger. In recent years, potential reservoirs have been discovered in older formations, prompting new trends in exploration and opening wider swaths of the GOM to drilling. As E&P companies venture into deeper waters in search of these reservoirs, new technologies must be developed, and old technologies must be modified to adapt to the challenges of this harsh operating environment.

Exploration forays into deep and ultradeep waters highlight the importance of well testing. To acquire meaningful results, the planning of these complex, extended well tests can take many months, and the tests themselves can run for several weeks. The flow, pressure and fluid-property data obtained through well testing are essential for developing further drilling, completion and production strategies. These data may dictate whether the operator sets pipe or abandons a prospect. If the operator elects to complete the well, the test data will guide the size and type of equipment required to process produced fluids.

To be successful in these deepwater frontier areas, exploration companies must employ a variety of sophisticated technologies that help them ascertain the nature of their prospects—which may lie beneath some 5,000 ft [1,500 m] or more of ocean, and perhaps 20,000 ft [6,100 m] or more beneath the seafloor. Initially, waves of pressure in the form of seismic energy penetrate the depths to define the prospect as clearly as possible. Once a well is drilled, however, an entirely different wave of pressure is used to ascertain its contents.

Chevron Corporation, along with partners Devon Energy and Statoil ASA, has been prospecting in the deeper Eocene formations of the Gulf of Mexico. In the process, Chevron's Jack 2 well, drilled at Walker Ridge Block 758, set a number of records while attaining the deepest successful test of a well in the GOM. The well is located 175 miles [280 km] offshore, about 270 miles [435 km] southwest of New Orleans, in 6,965 ft [2,123 m] of water. Targeting sands of the Wilcox trend, the Jack 2 well was drilled to a total depth of 28,175 ft [8,588 m] (right).

Initially proposed on the basis of seismic data, this subsalt reservoir had to be thoroughly logged and tested to ascertain the extent and quality of hydrocarbons contained within. The Chevron openhole formation evaluation program for the Jack 2 well included an LWD suite consisting of gamma ray, resistivity, pressure and directional services. Chevron also called for a comprehensive suite of wireline tools, including induction, density, neutron, elemental capture spectroscopy, natural gamma ray spectroscopy, sonic imager, magnetic resonance, seismic imager, formation tester and a rotary sidewall coring tool.

Although logging would aid in answering questions about depth, porosity, and gross and net feet of pay in the reservoir, production engineers were particularly concerned about the Wilcox potential for low permeability, low oil gravity, low-GOR oil and the impact of these factors on the deliverability or commercial potential of this prospect. Because of these concerns, this Wilcox reservoir was slated for a long-duration flow test to thoroughly define the deliverability of the reservoir.

Chevron assembled a project team with responsibility for planning and conducting the well test. Obtaining meaningful test results of a subsalt reservoir located some 20,000 ft beneath the seafloor required 14 months of extensive planning and coordination between Chevron, Schlumberger and other technical service providers. The core of Chevron's project team consisted of reservoir, operations and completion engineers, plus a completion advisor and a well test advisor, who reported to the Chevron Jack well test superintendent.

To coordinate the efforts of eight individual Schlumberger services and the services of other testing contractors, the Schlumberger Testing and Completion Project Support Group was contracted. The Schlumberger project manager was colocated with the Chevron well test team in Houston, and served as the single point of contact for all Schlumberger testing services. At the Schlumberger testing base in Houma, Louisiana, a senior operations coordinator handled logistics and oversaw the preparation, testing and qualification of massive amounts of equipment bound for the Jack well. This same operations coordinator would serve as the Schlumberger wellsite supervisor during the execution phase of the Jack well test, coordinating the team efforts of 25 Schlumberger and 10 third-party service personnel.

^ Preparing to test. The Jack 2 well, originally drilled by the *Discoverer Deep Seas* drillship, was cased and suspended before moving in the *Cajun Express* semisubmersible rig for the extended well test. Barges were brought in beforehand to collect fluids produced by the test.

This comprehensive planning process identified several areas of concern, especially with regard to the high bottomhole pressures encountered at such great depths. Schlumberger made several modifications to its completion and test equipment to permit extended operation at high pressures. Until this time, most of the downhole equipment was rated to 15,000 psi [103 MPa]. Among the downhole equipment deployed on the Jack well were IRIS downhole test tools and high-resolution pressure and temperature memory gauges. A specially modified 7-inch PowerFlow slug-free big hole tubing-conveyed perforating gun system complemented an eFire electronic firing head system that was designed for this job. All of this equipment was upgraded to withstand 25,000-psi [172-MPa] working pressures. On the well test, these tools would be spaced out beneath a SenTREE high-pressure subsea well control test tree that was precisely landed in the seafloor BOP stack. At the surface, a Vx multiphase flowmeter and PVT Express onsite fluid sampling and analysis services were provided to augment the traditional separator-based well testing suite.

The well was drilled to TD, cased and perforated using tubing-conveyed perforating (TCP) techniques. An upgraded eFire firing sequence was utilized to ensure that no misfires occurred because of pressure fluctuations in the annulus while tools were run in hole. The well was completed using a frac pack. Later, the well test string was run in the hole. During the first week of the test, a Schlumberger reservoir engineer was on site to integrate data streams and identify communication issues between service lines of tools supplied by Schlumberger, Halliburton, ClampOn AS and iicorr Ltd.

The 33-day well test involved two flow periods totaling 23 days, and two shut-in periods totaling 10 days. During the test, Oilphase-DBR personnel collected high-pressure, single-phase samples upstream of the choke, and low-pressure separator samples. The PVT Express analysis service performed real-time fluid analysis on these samples, and the results of this analysis were used on site to improve the fluid correlations of the Vx flowmeter. Aided by input from PVT Express fluid analysis, the Vx multiphase flowmeter provided precise and discrete rate measurements that were vital to several key real-time analyses performed by the Chevron engineering staff.

The Jack well test was no normal well test. Under normal well test conditions, real-time pressure measurement and analysis are advantageous, but with daily costs exceeding US$ 750,000 for the Jack well, they were indispensable. Critical decisions associated with timing and forward planning were regularly addressed, based on input from the surface readout of bottomhole pressures. Without this real-time data, conservative approaches would have been employed, resulting in considerably more days on location.

An important unknown for the Jack well was maximum safe drawdown pressure. Through preliminary studies, an aggressive target was set, and this target was predicated on actual well test behavior derived from bottomhole pressure readings. Without such pressure readings, real-time plotting of diagnostics could not have been carried out. Lacking these readings would have forced a more conservative testing program, resulting in lower tested rates and longer test periods.

A near-constant stream of bottomhole pressures also allowed for real-time pressure-transient analysis. This analysis was critical, not only during buildup portions of the test, but also during flowing periods. With real-time bottomhole pressures and instantaneous flow-rate data from the Vx multiphase flowmeter, Chevron engineers were able to correlate rate changes with pressure readings and perform accurate type-curve analysis on flowing data using superposition. When observing pressure-transient signatures associated with the well's completion, it was helpful to see these trends develop during flow periods as precursors to the cleaner real-time buildups. Chevron estimates that buildup durations were reduced by as much as 27 days through access to real-time bottomhole pressure data.

Though Chevron tested only 40% of the estimated 350 ft [107 m] of pay, the well flowed at a rate of 6,000 barrels [954 m^3] per day. The 33-day test was the longest drillstem test ever conducted under these severe conditions with test equipment at depth. In fact, more than a half-dozen world records for test equipment pressure, depth and duration in deep water were set during the Jack well test. For example, the perforating guns were fired at world-record depths and pressures. Additionally, the subsea test tree and other DST tools set world records, helping Chevron and co-owners conduct the deepest extended DST in deepwater Gulf of Mexico history while opening greater possibilities for new finds in the deepwater arena.

Data Integration and Interpretation

The behavior of reservoir fluids and their interactions with reservoir rock, and completion and production systems must be thoroughly characterized to produce a reservoir efficiently. This characterization is accomplished through reservoir modeling, and well test data provide a driving force for running model simulations.

Reservoir models are developed on a framework of geophysical, geological and petrophysical data. Dynamic well test data are integrated into this static framework to simulate and predict reservoir behavior. Data from descriptive well tests are particularly useful in detecting heterogeneities, permeability barriers, structural boundaries, fractures, fluid contacts and gradients that can be incorporated into the model.

Once a reservoir model is built, it is calibrated by comparing results of a test simulation against measured data to check its parameters. To achieve a good match between real and modeled data, the operator may need to fine-tune certain assumptions in the model concerning the well and its reservoir, such as permeability or distance to a fault, or other such parameters.

Production histories from wells in this field are then entered into the model. Another simulation is carried out to model pressures at the wellbore and across the reservoir. Simulation-derived fluid ratios and wellbore pressures are run through a history-matching process for comparison with measured production ratios and pressures. It is not unusual for initial results to disagree, in which case the model parameters are again changed. This iterative procedure continues until a good match is obtained between actual and simulated results. The reservoir model can then be used in predicting future production, well location and completion scenarios.

Well test pressures, flow rates and fluid compositions are also important criteria for nodal analysis. These data can help the operator analyze fluid movement from the outer boundary of production to the reservoir sandface, across perforations and up the tubing string, past the choke and out to the separator. Using nodal analysis, an operator can evaluate flow rate versus pressure drop along each node in the system and determine whether well production is constrained by its reservoir, downhole completion or surface production system.

But perhaps one of the most useful applications of well test data is achieved through pressure-transient analysis. By generating a log-log plot of measured pressure over time, when plotted along with the derivative of changing pressure, analysts are able to study pressure changes in great detail. The derivative of the pressure change provides a characteristic signature of reservoir pressure response to well testing that can be interpreted in terms of flow regimes, boundaries, permeability, formation damage, heterogeneities and reservoir volumes.

Well test data, when integrated into these and other advanced interpretation techniques help production teams understand their reservoirs and achieve their engineering and business objectives.[10]

Shaping the future

The field of well testing has changed dramatically since its earliest days in the 1920s, and work continues apace in new sampling and measurement techniques.

With the advent of highly accurate Vx multiphase well testing technology, introduced in the PhaseTester portable flowmeter and the permanently installed PhaseWatcher fixed multiphase well production monitoring device, the face of dynamic reservoir evaluation is beginning to change. And these changes are affecting the bottom line in well testing, through reduced cleanup periods and improved separation and effluent processing. Vx technology will undoubtedly increase the range of applications for multiphase flowmeters. This will open the way to different testing sequences and interpretation software to fully exploit the dataset acquired through the new technology.

The shape and scope of well testing will continue to evolve as technology strives to fulfill new testing objectives. — MV

10. For more on well testing and interpretation of test data: Schlumberger: *Fundamentals of Formation Testing*. Sugar Land, Texas: Schlumberger Marketing Communications, 2006.