Characterizing Permeability with Formation Testers

We never seem to know enough about permeability. We measure it at small scales through laboratory tests on cores. We infer it at large scales from well tests and production data. But to manage the development of a reservoir, we also need to quantify features at intermediate scales. This is where the versatility of wireline formation testers comes into play.

Cosan Ayan
Aberdeen, Scotland

Hafez Hafez
Abu Dhabi Company for Onshore Operations (ADCO)
Abu Dhabi, United Arab Emirates (UAE)

Sharon Hurst
Phillips Petroleum
Beijing, China

Fikri Kuchuk
Dubai, UAE

Aubrey O'Callaghan
Puerto La Cruz, Venezuela

John Peffer
Anadarko
Hassi Messaoud, Algeria

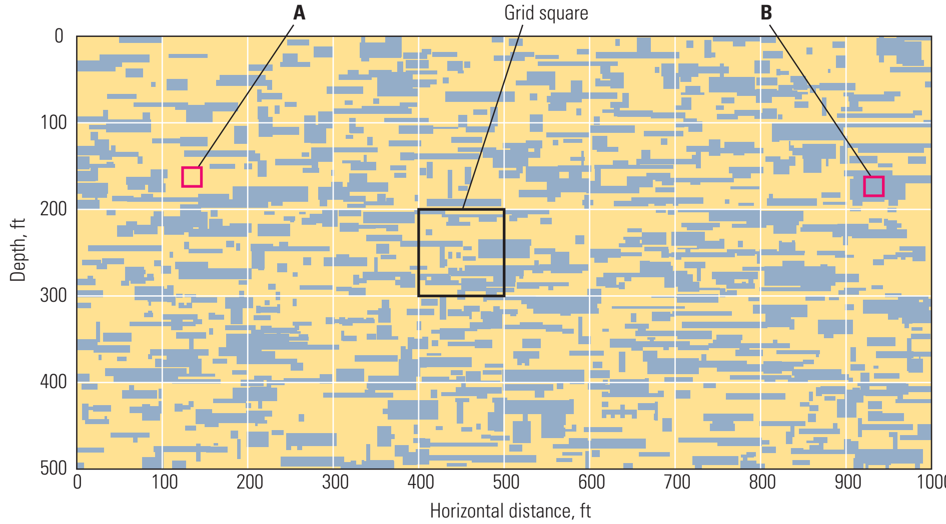
Julian Pop
Sugar Land, Texas, USA

Murat Zeybek
Al-Khobar, Saudi Arabia

For help in preparation of this article, thanks to Mahmood Akbar, Abu Dhabi, UAE.

1. In direct measurements of fluid flow in rocks, the quantity measured is the mobility (permeability/viscosity). According to Darcy's law, all fluid effects are accounted for by the viscosity term, and permeability is independent of fluid. In practice, this is not exactly true, even without chemical interactions between rock and fluid. Absolute permeability is also known as intrinsic permeability.
2. The term radial permeability, k_r, describes radial flow into a wellbore. In vertical wells, radial permeability is the same as horizontal permeability. Vertical permeability is written both as k_v and k_z. Spherical permeability is written as k_s.

Modern wireline formation testers bring special knowledge about reservoir dynamics that no other tool can acquire. Through multiple pressure-transient tests, they can evaluate vertical as well as horizontal permeability. By measuring at a length scale between cores and well tests, they can quantify the effect of thin layers that are not seen by other techniques. These layers play a vital role in reservoir drainage, controlling gas- and waterflood performance, and leading to unwanted gas and water entries. Modern wireline formation testers can also be a cost-effective, environmentally friendly alternative to regular drillstem and pressure-transient tests. This article shows how permeability measurements derived from wireline formation testers are contributing to reservoir understanding and making an impact on reservoir development.



^ A cross section of an idealized reservoir that exhibits large-scale anisotropy caused by local heterogeneity. A sandstone reservoir (yellow) contains randomly distributed shales (gray). The vertical permeability for the whole reservoir is about 10^4 times less than the horizontal permeability—a very large anisotropy. However, the small areas A and B are in isotropic sand and shale, respectively. The grid square, which might represent a reservoir-simulation block, has intermediate permeability anisotropy. Vertical permeability is close to the harmonic average of sand and shale permeabilities, while the horizontal permeability is the arithmetic average. [Adapted from Lake LW: "The Origins of Anisotropy," *Journal of Petroleum Technology* 40, no. 4 (April 1988): 395–396.]

Which Permeability?

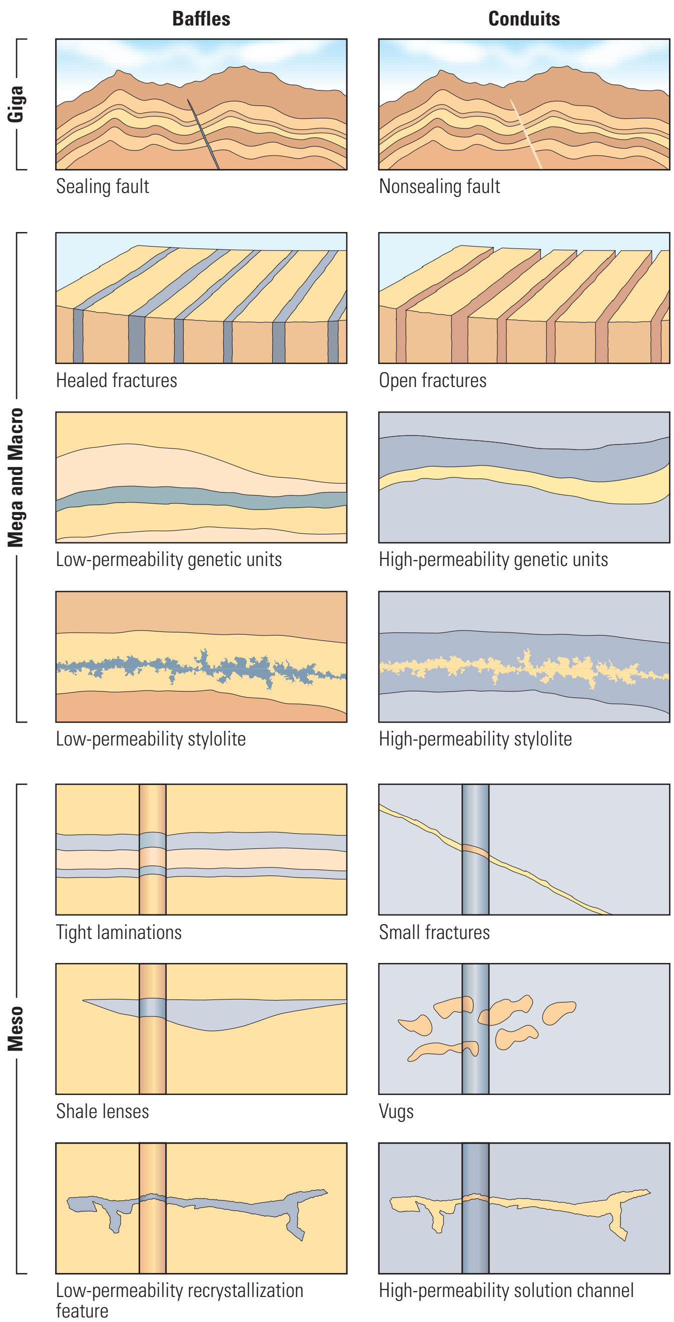
Permeability determines reservoir and well performance, but the term can refer to many types of measurements. For example, permeability can be absolute or effective, horizontal or vertical. Permeability is defined as a formation property, independent of the fluid. When a single fluid flows through the formation, we can measure an absolute permeability that is more or less independent of the fluid.[1] However, when two or more fluids are present, each reduces the ability of the other to flow. The effective permeability is the permeability of each fluid in the presence of the others, and the relative permeability is the ratio of effective to absolute permeability. In a producing reservoir, we are most interested in effective permeability, initially of oil or gas in the presence of irreducible water, and later of oil, gas and water at different saturations. To further complicate matters, effective and absolute permeabilities can be significantly different (see "Conventional Permeability Measurements," *page 6*).

Formations are usually anisotropic, meaning their properties depend on the direction in which they are measured. For fluid-flow properties, we usually consider transversely isotropic formations, meaning formations in which the two horizontal permeabilities are the same and equal to k_h, while the vertical permeability, k_v, is different. Although more complicated formations exist, there are typically not enough measurements to quantify more than these two quantities. Permeability anisotropy can be defined as k_v/k_h, k_h/k_v, or the ratio of the highest to the lowest permeability. In this article we will use k_h/k_v, a quantity that is most often greater than 1.[2]

The next complication is related to spatial distribution. Reservoir management would be much simpler if permeability were distributed uniformly, but, in practice, formations are complex and heterogeneous—that is, they have a range of values about two or more local averages. The number of measurements needed for a full description of a heterogeneous rock is impossibly high; moreover, the result of each measurement depends on its scale. For example, for an idealized reservoir comprising isotropic sand with randomly distributed isotropic shales, there are three scales to consider—megascopic (the overall reservoir), macroscopic (the grid squares used in reservoir simulation), and mesoscopic (individual facies) (above). The megascopic anisotropy is very high—between 10^3 and 10^5. However, areas A and B are isotropic, while the grid squares are intermediate, showing that the large-scale anisotropy is in fact caused by local heterogeneity. Measurements at different scales and in different locations will find different values for both k_h and k_v and hence different anisotropy.

Which permeability to choose? In a single-phase, homogeneous reservoir, the question is irrelevant—but such reservoirs do not exist. Almost all reservoirs, and particularly carbonates, are highly stratified. For some formations, flow properties also vary laterally. For instance, in deltaic sandstone deposits, the world's most prolific reservoirs, flow properties vary laterally because of the sorting of sediments according to size and weight during transport and deposition. Whether in sandstone or carbonate, as heterogeneity increases, the distribution of permeability becomes as important as its average value.

Early in the life of a reservoir, the main concern is the average horizontal effective permeability to oil or gas, since this controls the productivity and completion design of individual wells. Later on, vertical permeability becomes important because of its effect on gas and water coning, as well as the productivity of horizontal and multilateral wells. The distribution of both horizontal and vertical permeability strongly affects reservoir performance and the amount of hydrocarbon recovery, while also determining the viability of secondary- and tertiary-recovery processes.



^ Permeability baffles and conduits at different length scales. In each case, reservoir management can be improved by quantifying the effects of these features.

The magnitude of permeability contrast becomes increasingly important with prolonged production. Thin layers, faults and fractures can have a dramatic effect on the movement of a gas cap, aquifer, and injected gas and water. For example, a low-permeability layer, or baffle, will impede the movement of gas downwards. A high-permeability layer, or conduit, will quickly bring unwanted water to a production well. Both can significantly affect the sweep efficiency and require a change in completion practices. Sound reservoir management depends on knowing not only the average horizontal permeability but also the permeability distribution laterally and vertically, and the conductivity of baffles and conduits (left). As has been known for a long time, reservoir heterogeneity is one of the major reasons why enhanced oil recovery is so difficult. Permeability heterogeneity, unexpected baffles and insufficiently detailed reservoir evaluation are often the reasons that these projects fail to be economical.[3]

In normal reservoir-engineering practice, the main sources of average effective permeability are pressure-transient well testing and production tests. These are usually good indicators of overall well performance. Cores and logs are used, but often after some matching, or scaling up, to well-test results. Once a reservoir has been on production, conventional history matching gives information on average permeability, but cannot resolve its distribution. The presence of high- or low-permeability streaks and their distributions are inferred from cores and logs, but this information is qualitative rather than quantitative. Wireline formation testers (WFTs) have stepped into this gap, providing various measurements of permeability from simple drawdowns with a single probe to multilayer analyses with multiple probes. The latter were originally used mainly to determine anisotropy.[4] With recently developed analytical techniques and further experience, multilayer analyses now provide quantitative information about permeability distribution.

Wireline Formation Testers

Early wireline formation testers were designed primarily to collect fluid samples. Pressures were recorded, so that the pressure buildups at the end of sampling could be analyzed to determine permeability and formation pressure. In spite of the limited gauge resolution and the few data points available, the results were often an important input to formation evaluation. Now, buildups acquired after sampling are still analyzed to obtain an estimate of permeability at little extra cost.

The Schlumberger RFT Repeat Formation Tester tool introduced the pretest, a short test

3. Weber AG and Simpson RE: "Gasfield Development—Reservoir and Production Operations Planning," *Journal of Petroleum Technology* 38, no. 2 (February 1986): 217-226.
4. Ayan C, Colley N, Cowan G, Ezekwe E, Wannel M, Goode P, Halford F, Joseph J, Mongini A, Obondoko G and Pop J: "Measuring Permeability Anisotropy: The Latest Approach," *Oilfield Review* 6, no. 4 (October 1994): 24-35.
5. The so-called drawdown permeability is calculated as $k_d = C\, q\mu/\Delta p_{ss}$ in units of mD, where q is the flow rate in cm^3/s, μ is the fluid viscosity in cp, and Δp_{ss} is the measured drawdown pressure in psi (and therefore includes any pressure drop due to mechanical skin). C, the flow-shape factor, depends on the effective radius of the probe, and equals 5660 for the standard RFT and MDT Modular Formation Dynamics Tester probes and the units given.
6. Dussan EB and Sharma Y: "Analysis of the Pressure Response of a Single-Probe Formation Tester," *SPE Formation Evaluation* 7, no. 2 (June 1992): 151-156.
7. Jensen CL and Mayson HJ: "Evaluation of Permeabilities Determined from Repeat Formation Tester Measurements Made in the Prudhoe Bay Field," paper SPE 14400, presented at the SPE Annual Technical Conference and Exhibition, Las Vegas, Nevada, USA, September 22-25, 1985.
8. Goode PA and Thambynayagam RKM: "Influence of an Invaded Zone on a Multiple Probe Formation Tester," paper SPE 23030, presented at the SPE Asia Pacific Conference, Perth, Western Australia, Australia, November 4-7, 1991.

   We might expect the buildup permeability to be higher than k_d since, by reading farther into the formation, it should read closer to the effective permeability of the formation to oil or gas. However, in general experience, the buildup permeability reads lower.

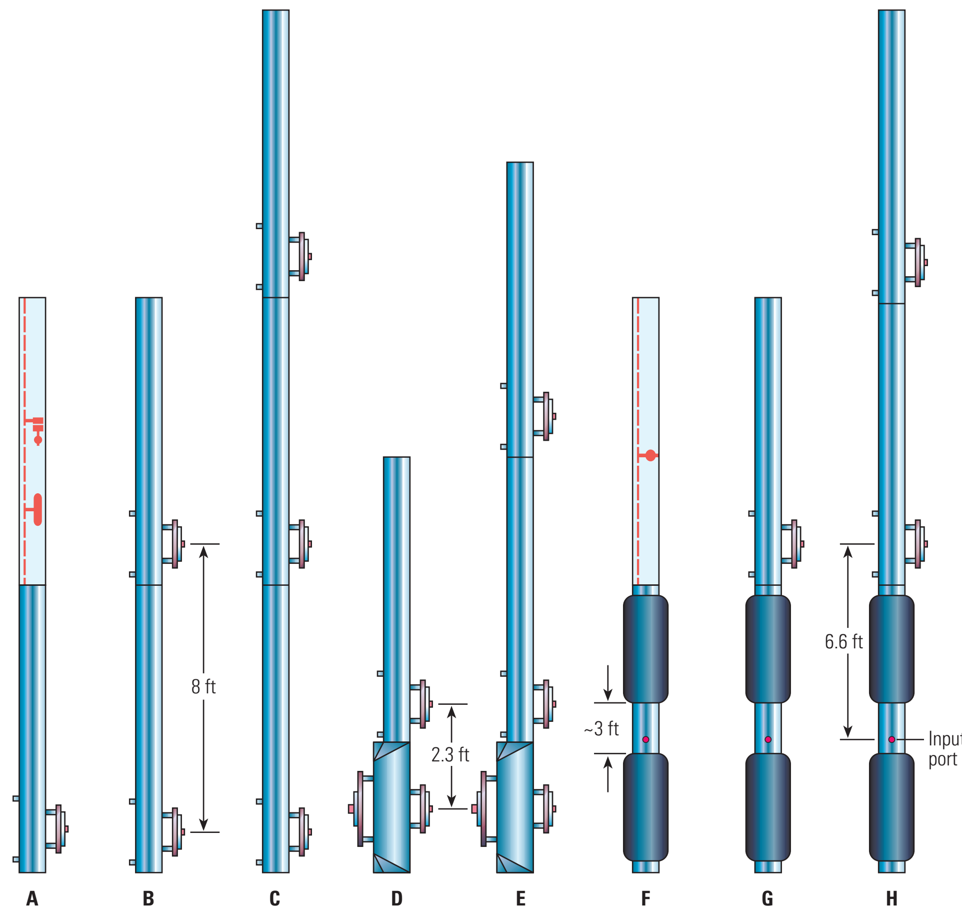
initially designed to determine whether a point was worth sampling. To the surprise of many, pretest pressure turned out to be representative of reservoir pressure. As a result, pressure measurements became the main WFT application. Permeability could be estimated from both the drawdown and the buildup during a pretest. Since a reliable pressure gradient required pretests at several depths, much more permeability data became available. With tens of test points in a single well, it became easier to establish a permeability profile and compare results with core and other sources.

Pretests continue to be an important feature of modern tools, although the reliability of the permeability estimate varies. Since pretests sample a small volume, typically 5 to 20 cm^3 [0.3 to 1.2 $in.^3$], the drawdown permeability, k_d, can be overly influenced by formation damage and other near-wellbore features.[5] Detailed analysis shows that k_d is closest to k_h, although it is influenced by k_v.[6] The volume of investigation is significantly larger than that of a core plug, but of the same order of magnitude. However, k_d is typically the effective permeability to mud filtrate in the invaded zone rather than the absolute permeability as obtained from core. Although some good correlations between the two have been found, k_d is generally considered to be the minimum likely permeability.[7] Nevertheless, it can be computed automatically at the wellsite, and is still used regularly as a qualitative indicator of productivity.

Pretest buildups investigate farther into the formation than drawdowns, several feet if the gauge resolution is sufficiently high and the buildup is recorded long enough. Except in low-permeability formations, buildup time is short, so that the tool may be measuring the permeability of either the invaded zone, the noninvaded zone, or some combination of the two.[8] As in the interpretation of any pressure-transient data, flow regimes are identified by looking for characteristic gradients in the rate of change of pressure with time. For pretest buildups in which the flow regimes are spherical and occasionally radial, consistent gradients often prove hard to find, and even then may be affected by small changes in the pretest sampling volume. For reliable results, each pretest must be analyzed—a time-consuming process. Today, the analysis of short pretest buildups for permeability is rare, mainly because there are much better ways to obtain permeability with modern tools.

Modular Wireline Formation Testers

The third-generation WFT is the modular tester. This tool can be configured with different modules to satisfy different applications, or to handle varying conditions of well and formation (below).



	A	B	C	D	E	F	G	H
Usually	k_s	k_h,k_v	k_h,k_v	k_h,k_v,ϕC_t	k_h,k_v,ϕC_t	k_s and/or k_h	k_h,k_v	k_h,k_v
Sometimes	k_h		ϕC_t					ϕC_t

^ Typical MDT tool configurations for permeability measurements: single probe with sample chamber and flow-control module (A); a sink, normally the bottom probe, with one (B) or two (C) vertical observation probes; dual-probe module with one (D) or two (E) vertical probes; mini-DST configuration with dual-packer and pumpout module (F); dual-packer module with one (G) or two (H) vertical probes. The flow-control module, sample chamber and pumpout module can be added to any configuration. When only one pressure transient is recorded, as in (A) and (F), permeability determination depends on identifying particular flow regimes, type-curve matching or parameter estimation using a forward model. With one or more vertical probes, as in the other configurations, it is possible to perform a local interference test, also known as an interval pressure-transient test (IPTT). With these tests, interpreters can determine k_v and k_h for a limited number of layers near the tool. Storativity, $øC_t$, can be determined with the dual-probe module, and sometimes when three vertical transients are available, as in (C) and (H). With other configurations, it must be determined from other data. Pretest drawdown and buildup permeabilities can be determined with the dual-packer module and each probe in all configurations.

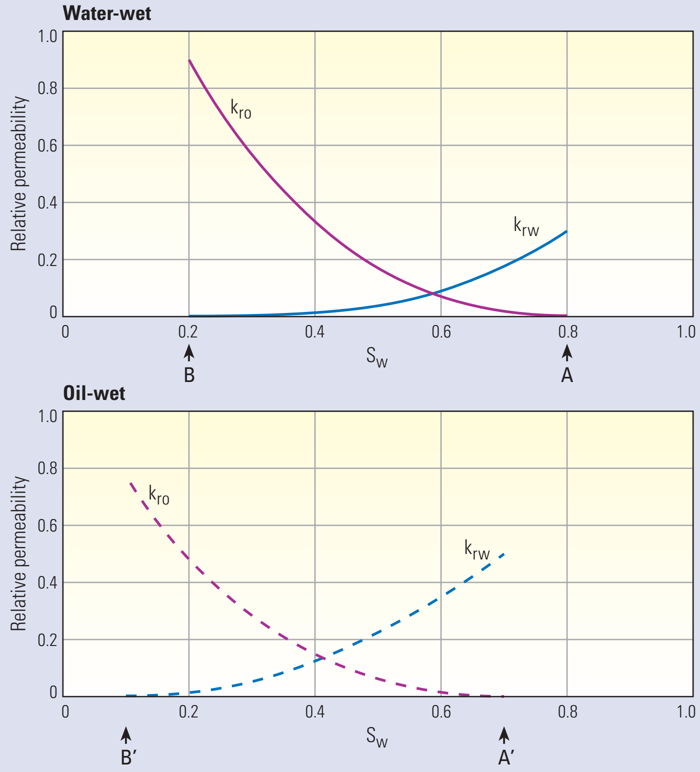
Conventional Permeability Measurements

Pressure-transient analysis, production tests, history data, cores and logs are all used to estimate permeability. Each measurement has different characteristics, advantages and disadvantages.

Core data—Routine core measurements give absolute, or intrinsic, permeability. In shaly reservoirs with high water saturation or in oil-wet reservoirs, the effective permeability can be significantly lower than the absolute permeability (right). Core data are taken on samples that have been moved to surface and cleaned, so that measurement conditions are not the same as those made in situ. Some of these conditions, such as downhole stress, can be simulated on surface. Others, such as clay alteration and stress-relief cracks, may not be reversible.

To be useful for reservoir characterization, there should be enough core samples to capture sufficiently the reservoir heterogeneity—various statistical rules exist to determine how many samples are required. But it is not always possible to capture a statistically valid range of samples even in one well. Highly porous samples may fall out of the core barrel, while cutting plugs from very tight intervals is difficult. Some analysts prefer permeameter measurements because more samples can be taken.[1] Averaging, or scaling up, is another tricky issue. For layered flow, the arithmetic average, $k_{av} = [\sum k_i h_i / \sum h_i]$, is the most appropriate for the horizontal permeability. For random two-dimensional flow, it is the geometric average, $k_{av} = [\prod k_i^{\,h_i/\sum h_i}]$, while for the vertical permeability, the harmonic average, $k_{av} = [\sum k_i^{-1} h_i / \sum h_i]^{-1}$, is important.[2]

Log data—Logs measure porosity and other quantities that are related to pore size, for example irreducible water saturation and nuclear magnetic resonance parameters.[3] Permeability can be estimated from these measurements using a suitable empirical relationship. This relationship normally must be calibrated for each reservoir or area to more direct measurements, usually cores, but sometimes, after scaling up, to pressure-transient results. The main use of log-derived permeability is to provide continuous estimates in all wells. On the economic side, cores and logs have many applications, so that the extra cost of obtaining permeability from them is relatively small.



^ Typical relative-permeability curves for oil and water in a water-wet reservoir (*top*) and an oil-wet reservoir (*bottom*). Effective permeabilities are relative permeabilities multiplied by the absolute permeability. Points A and A' represent the typical situation for a wireline formation tester drawdown measurement in water-base mud. In a water-wet reservoir, the filtrate flows in the presence of 20% residual oil and has a relative permeability of 0.3. Points B and B' represent the typical situation for pressure-transient analysis in an oil reservoir. In a water-wet reservoir, the oil flows in the presence of 20% irreducible water and has a relative permeability of 0.9. Points A, A', B and B' are also known as endpoint permeabilities. Some engineers refer relative permeabilities to the effective permeability to oil rather than the absolute permeability, as shown here.

Well tests—Pressure-transient analysis of well tests measures the average in-situ, effective permeability of the reservoir. However, the results have to be interpreted from the change of pressure with time. Interpreters use several techniques, including the analysis of specific flow regimes, and matching the transient to type curves or a formation model. In conventional tests, the well is produced long enough to sample up to the reservoir boundaries. Impulse tests produce for a short time and are useful for wells that do not flow to surface. In both cases, but especially for impulse tests, there is not necessarily any unique solution for permeability.

In most conventional tests, the goal is to measure the transmissivity ($k_h h/\mu$) during radial flow. The reservoir thickness, h, can be estimated at the borehole, but is it the same tens and hundreds of feet into the reservoir where the pressure changes are taking place? In practice, other information—geological models and seismic data—helps improve results. With conventional well tests, the degree of heterogeneity can be detected, but the permeability distribution cannot be determined and there is no vertical resolution.

Economically, well tests are expensive from the point of view of both equipment and rig time. Well tests are also undertaken to obtain a fluid sample so that the incremental cost of determining permeability may be small. However, obtaining high-quality permeability data often requires long shut-in times and extra equipment such as downhole valves, gauges and flowmeters.[4]

Production tests and production history—An average effective permeability can be obtained from the flow rate and pressure during steady-state production, preferably from specific tests at different flow rates. Skin and other near-wellbore effects have to be known or assumed. An average permeability can also be determined from production-history data by adjusting the permeability until the correct history of production is obtained. However, in both cases, the permeability distribution cannot be obtained reliably. In the presence of layering or heterogeneity, this is a highly nonlinear inverse problem, for which there can be more than one solution.

In the absence of other data, permeability is often related to porosity. In theory, the relation is weak—there are porous media that have been leached to give high porosity with zero permeability, and others that have been fractured to give the opposite. However, in practice, there do exist well-sorted sandstone reservoirs with a consistent porosity-permeability relation. Other reservoirs are less simple. For carbonate rocks in particular, microporosity and fractures make it almost impossible to relate porosity and lithofacies to permeability.

Some of these modules are particularly relevant for permeability measurements. The descriptions of the modules below refer to the Schlumberger MDT Modular Formation Dynamics Tester tool, unless otherwise specified.

The single-probe module—This module provides communication between the reservoir and the tool. It consists of the probe assembly, pretest chamber, strain and quartz pressure gauges, and resistivity and temperature sensors. The probe assembly has a small packer, which contains the actual probe. When a tool is set, telescoping backup pistons press the packer assembly against the borehole wall. The probe is pressed farther through the mudcake into contact with the formation. Special probe-assembly designs are available for difficult conditions.[9] Communication is established with the formation by a short pretest, after which the module can withdraw fluids for sampling or act as a passive monitor of pressure changes.

The dual-probe module—This module consists of two probe assemblies mounted in fixed positions on the same mandrel. In the Halliburton RDT Reservoir Description Tool, the probes are mounted above one another, separated by a few inches and facing the same way.[10] One probe, known as the sink probe, withdraws fluids, while the other monitors the pressure transient. In the MDT tool, the two probe assemblies are mounted diametrically opposite each other on the mandrel.[11] One probe is a sink while the other, known as the horizontal probe, is solely a monitor with no sampling capability. The main purpose of the dual-probe module is to combine with a vertical probe to determine k_h, k_v and storativity ($øC_t$) through a local interference test or, to use a more specific name, the interval pressure-transient test (IPTT).[12] By withdrawing fluid through the sink, three pressure transients can be recorded at three different locations along the wellbore, two of which are from monitor probes and are not contaminated by the effects of tool storage, skin and cleanup.[13]

The dual-packer module—This module has two packer elements that are inflated to isolate a borehole interval of about 1 m [3.3 ft]. Once these are inflated, fluid is withdrawn, first from the isolated interval, and then from the formation. Since a large section of the borehole wall is now open to the formation, the fluid-flow area is several thousand times larger than that of conventional probes. This offers important advantages in both low- and high-permeability formations, and in other situations.

- Probes are sometimes ineffective when set in laminated, shaly, fractured, vuggy, unconsolidated or low-permeability formations. The dual packer allows pressure measurements and sampling in these conditions.
- Used alone, the dual packer makes a small version of a standard drillstem test (DST) that is known as a mini-drillstem test, or mini-DST. Since the mini-DST opens up only 1 meter of formation, it acts as a limited-entry test from which both k_v and k_h may be determined under favorable conditions. Used in combination with one or more vertical probes, the dual packer can record an IPTT.
- The pressure drop during drawdown is typically much smaller than that obtained with a probe. Thus, it is easier to ensure that oil is produced above its bubblepoint, and that unconsolidated sands do not collapse. Also, with a smaller pressure drop, fluids can be pumped at a higher rate, so that for the same time period, a larger volume of formation fluid can be withdrawn and a deeper-reading pressure pulse created.

1. Zheng S-Y, Corbett PWM, Ryseth A and Stewart G: "Uncertainty in Well Test and Core Permeabilty Analysis: A Case Study in Fluvial Channel Reservoirs, Northern North Sea, Norway," *AAPG Bulletin* 84, no. 12 (December 2000): 1929–1954.
2. Pickup GE, Ringrose PS, Corbett PWM, Jensen JL and Sorbie KS: "Geology, Geometry, and Effective Flow," paper SPE 28374, presented at the SPE Annual Technical Conference and Exhibition, New Orleans, Louisiana, USA, September 25-28, 1994.
3. Herron MM, Johnson DL and Schwartz LM: "A Robust Permeability Estimator for Siliclastics," paper SPE 49301, presented at the SPE Annual Technical Conference and Exhibition, New Orleans, Louisiana, USA, September 27-30, 1998.
4. *Modern Reservoir Testing.* SMP-7055, Houston, Texas, USA: Schlumberger Wireline & Testing, 1994.

9. For the MDT tool these include: large-area packers for tight formations; large-diameter probes for unconsolidated as well as tight formations; long-nosed probes for unconsolidated formations and thick mudcakes; and gravel-pack probes and a large-area filter similar to an automobile oil filter for extremely unconsolidated sands (the Martineau probe).
10. Proett MA, Wilson CC and Batakrishna M: "Advanced Permeability and Anisotropy Measurements While Testing and Sampling in Real-Time Using a Dual Probe Formation Tester," paper SPE 62919, presented at the SPE Annual Technical Conference and Exhibition, Dallas, Texas, USA, October 1-4, 2000.
11. Zimmerman T, MacInnes J, Hoppe J, Pop J and Long T: "Applications of Emerging Wireline Formation Testing Technologies," paper OSEA 90105, presented at the 8th Offshore Southeast Asia Conference, Singapore, December 4-7, 1990.
12. The term vertical interference test (VIT) is also used for vertical wells. The terms local interference test and interval pressure-transient test are appropriate for deviated or horizontal wells.

    Storativity is the product of porosity, $ø$, and total rock compressibility, C_t, which is the sum of the solid compressibility, C_r, and the fluid compressibility, C_f. When not measured by an IPTT, C_f must be estimated from fluid properties and C_r from knowledge of the solid framework based on acoustic logs, porosity and other data. If there is more than one fluid, the saturation of each fluid is estimated from logs or sample volumes.
13. Skin is defined as the extra pressure drop caused by near-wellbore damage (mechanical skin), flow convergence in a partially penetrated bed, and viscoinertial flow effects (usually ignored). The flow-convergence factor can be calculated from knowledge of bed thickness and test interval.

    Tool storage is due to the compressibility of the fluid in the tool, and causes the measured flow rate to be different from the actual flow rate at the formation surface, or sandface. Cleanup refers to the increase in flow rate as the flow of fluids removes formation damage near the borehole.

The pumpout module—This module pumps fluid from the formation into the mud column, and from one part of the tool to another. Pumping into the mud column allows much larger volumes of fluid to be withdrawn than when sampling into fixed-volume sample chambers. The module can also pump fluid from one part of the tool to another; from the mud column into the tool, for example to inflate the packer elements; or into the interval between the packers to initiate a small hydraulic fracture. For permeability measurements, the pumpout module is capable of sustaining a constant, measured flow rate during drawdown, thereby simplifying considerably the interpretation of pressure transients. The flow rate though the pump depends on the pressure differential, increasing at low differential to a maximum of 45 cm^3/s [0.7 gal/min]. At very high differential, such as in a tight rock, the pump may not be able to maintain a constant rate.

The flow-control module—This module withdraws up to 1000 cm^3 [0.26 gal] of fluid from the formation while controlling and measuring the flow rate. The fluid withdrawn is either sent to a sample chamber or pumped into the borehole. The module works in various modes such as constant flow rate, constant pressure and ramped pressure, and can also draw repeated pulses of fluid from the formation. The time for pulses to arrive at a vertical probe is an important input in the determination of k_v. Since the flow-control module can control flow rate precisely, it can regulate the withdrawal of sensitive formation fluids into small-volume pressure-volume-temperature (PVT) sample bottles. This is important for the sampling of condensate reservoirs. (For more on sampling, see "Quantifying Contamination Using Color of Crude and Condensate," *page 24*).

All these features provide many ways to measure permeability, ranging from simple pretest drawdown to multiple probes and dual packers (right). For the most reliable in-situ determination of permeability and anisotropy, experience has shown that interference tests should be performed with multiple pressure transients. Results from other methods will always be more ambiguous, but can still be useful, and even good, estimates in the right conditions. One such technique is the mini-DST.

Flow Source	**Advantages**	**Limitations**
Probe	• Simplest method of establishing communication with formation • Multiple probes can be added in one tool string	• Difficult to get good tests in fractured, vuggy and tight formations (difficult to withdraw fluids, seal failures) • High drawdowns in low k/μ formations may release gas, complicating analysis
Dual packer	• Easier to test fractured, vuggy and tight formations • At same flow rate as probe, less drawdown helps avoid gas and sanding • For same time period as probe, more fluid is withdrawn, creating deeper pulse	• Fear (usually unjustified) of sticking or of releasing gas slug into borehole • Low drawdown may give insignificant signals at vertical probes in high k/μ formations
Probe Pretest		
Drawdown	• Automatic computation, available during acquisition • Many (tens) of pretests often recorded for pressure, allowing qualitative comparisons	• Small volume of investigation (inches) • Measures effective permeabiliby to mud filtrate
Buildup	• Deeper radius of investigation than drawdown • Many (tens) of pretests often recorded for pressure, allowing qualitative comparisons	• Small sampling volume, cleanup and tool storage can make analysis difficult • Measures effective permeability to mud filtrate, formation fluid or a mixture of the two
Single-Transient Analysis		
Dual-packer mini-DST or extended drawdown and buildup with probe	• Data available while sampling • Gives k_s and/or k_h and can avoid costly DST	• Need a particular combination of formation properties and thickness to get both k_v and k_h • Need to know ϕC_t to get k_s, and need to know h to get k_h • Tool storage, skin, free gas and continuous cleanup can complicate analysis (especially with probe)
Dual-Transient IPTT		
Dual packer + probe or tandem probes	• Gives k_h and k_v • The simplest configuration for an IPTT	• Need to have a good idea of ϕC_t • Sink drawdown and early buildup affected by tool storage, skin, free gas and cleanup
Multiple-Transient IPTT		
Three probe (sink, horizontal and vertical)	• Analysis can be done without sink drawdown • Gives ϕC_t as well as k_h and k_v	• Smaller vertical investigation than other IPTT configurations (sometimes an advantage)
Second vertical probe	• Best configuration for layered reservoirs, faults and fractures • Analysis can be done without sink drawdown	• Longer tool

^ Features of the flow sources and methods used to derive permeability from the MDT tool.

Mini-DSTs

In a standard DST, drillers isolate an interval of the borehole and induce formation fluids to flow to surface, where they measure flow volumes before burning or sending the fluids to a disposal tank. For safety reasons, many DSTs require the well to be cased, cemented and perforated beforehand. The MDT tool, in particular the dual-packer module, provides similar functions to a DST but on wireline and at a smaller scale.

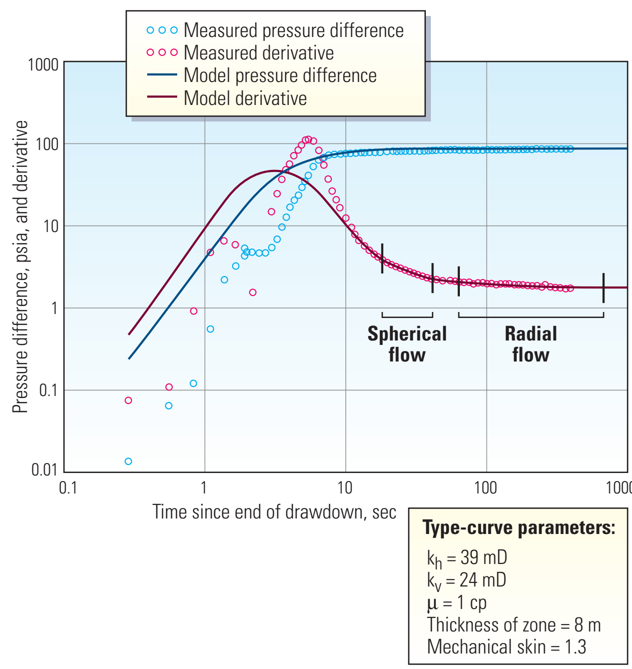
The advantages of the mini-DST are less cost and no fluids to surface. Cost benefits come from cheaper downhole equipment, shorter operating time and the avoidance of any surface-handling equipment. On offshore appraisal wells, cost savings can be more than $5 million. With no fluids flowing to surface, there are no problems of fluid disposal, no surface safety issues and no problems with local environmental regulations. Mini-DSTs are much easier to plan and can test multiple stations on the same trip—usually a sufficient number to sample the entire reservoir interval.

The mini-DST has disadvantages: it investigates a smaller volume of formation due to the smaller packed-off interval (3 ft versus tens of feet), and withdraws a smaller amount of fluid at a lower flow rate. In theory, we may be able to extend the tests and withdraw large amounts of fluid, but in practice, there may be a limit to how long the tool can safely be left in the hole.[14] The actual depth of investigation of a wireline tester depends on formation permeability and other factors, but is of the order of tens of feet, rather than the hundreds of feet seen by a normal DST.

The smaller volume of investigation is not necessarily a disadvantage. A full DST reveals the average reservoir characteristics and assesses the initial producibility of a well. Permeability variations will be averaged, and although they contribute to the average, they are neither located nor quantified. With the help of logs, the smaller volume mini-DST can evaluate key intervals. The procedure for interpreting pressure transients from mini-DSTs is the same as for full DSTs and the same software can be used for both.

TotalFinaElf used mini-DSTs in the Arab reservoir of an aging Middle East field to look for zones with moveable oil and to calibrate the permeability anisotropy used in a simulation model.[15] Since the packed-off interval rarely covers the whole reservoir, a mini-DST is a limited-entry, or partially penetrating, well test. To determine formation parameters, interpreters need to identify flow regimes in the buildup. In a homogeneous layer, there are three flow regimes: early radial flow around the packed-off interval, pseudospherical flow until the pressure pulse reaches a boundary, and finally total radial flow between upper and lower no-flow boundaries. Rarely are all three seen because tool storage effects can mask the early radial flow, while the distance to the nearest barrier determines whether or not the other regimes are developed during the test period.[16] However, it has been common to observe a pseudospherical flow regime, and occasionally total radial flow in buildup tests (below). On a log-log plot of the pressure derivative versus a particular function of time, spherical flow is identified by a slope of –0.5, and radial flow by a stabilized horizontal line.

Spherical permeability, $k_s = \sqrt[3]{(k_h^2 k_v)}$ can be estimated from a pressure-derivative plot during spherical flow or from a separate specialized plot.[17] Horizontal permeability, k_h, can be estimated from a pressure-derivative plot during radial flow, or from a specialized plot of pressure versus Horner time, provided the thickness of the interval is known.[18] In this case, the thickness was obtained from openhole logs, particularly images from the Schlumberger FMI Fullbore Formation MicroImager tool. When both spherical- and radial-flow regimes occurred, the interpreters could estimate vertical permeability, k_v, from k_h and k_s. These initial estimates were combined with the geological data to build a model of formation properties. Different analytical techniques, such as type-curve matching, were then used to match the full pressure transient and improve the permeability estimates.



^ Pressure difference and the derivative of pressure with respect to a function of time for the buildup at the end of a typical mini-DST. The pressure difference is between the measured pressure and a reference taken near the end of the drawdown period. The derivative is calculated from $d\Delta p/d\ln[(t_p+\Delta t)/\Delta t]$ where t_p is the producing time and Δt is the time since the end of the drawdown. We identify spherical flow by the slope of –0.5 on the log-log derivative, and radial flow by the slope of 0 (horizontal). The solid lines are the results of a type curve, or model, computed with the parameters in the table.

14. In one recent job, the pumpout module was run continuously for 36 hours. In another job, the dual-packer module was in the hole for 11 days.

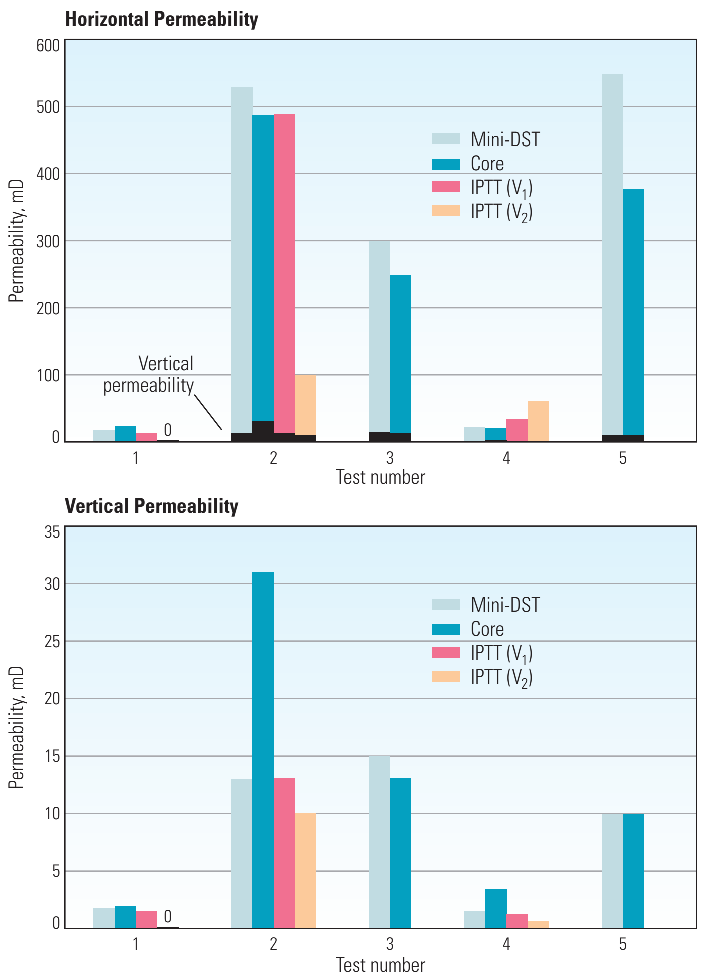
15. Ayan C and Nicolle G: "Reservoir Fluid Identification and Testing with a Modular Formation Tester in an Aging Field," paper SPE 49528, presented at the 8th Abu Dhabi International Petroleum Exhibition and Conference, Abu Dhabi, UAE, October 11-14, 1998.

16. Tool storage includes the compressibility of the fluid between the packers. A common model is to relate the sandface flow rate, q_{sf}, to the measured flow rate, q, and the rate of change of pressure by a constant, C: $q_{sf} = q+24C dp/dt$. The very early part of a buildup is dominated by wellbore storage, also called afterflow. C can be estimated from the rate of change of pressure at this time.

17. On a specialized spherical plot, the slope, m_{sp} during spherical flow is given by: $m_{sp} = 2453 q\mu(\sqrt{\mu \o C_t})/k_s^{3/2}$ in oilfield units, where $\o$ is usually taken from logs, and q, the flow rate, is measured or estimated. The viscocity, μ, is determined from the PVT properties of the mobile fluids. If there is more than one mobile fluid, their saturations are estimated from logs or sample volumes.

18. Horner time is $[(t_p+\Delta t)/\Delta t]$ where t_p is the drawdown time, and Δt is the time since the end of the drawdown. The slope, m_r, during radial flow is given by $m_r = 162 q\mu/k_h h$, where h is the thickness of the formation interval, and the other terms are defined in reference 17.

TotalFinaElf recorded ten tests in two wells, one of which was cored. Both k_v and k_h were subsequently measured on core plugs sampled every 0.25 or 0.5 m [9.8 or 19.6 in.], and compared with the mini-DST results (below). Care was taken to scale up the core data to the mini-DST interval and to convert from absolute to effective permeability. For some of the tests, pressure-transient data were also available from two probes in the MDT tool string, making it possible to compare mini-DST results with results from a full IPTT as well as from core samples. The IPTTs measure larger volumes of formation, yet the results generally agree with the mini-DST, especially for the near probe. The fact that the different measurements agree suggests that the formations may be relatively homogeneous, or that the scaling up of the core data was appropriate. While this good agreement validates the use of a mini-DST in these conditions, it is inadvisable to assume the same degree of homogeneity in other formations.



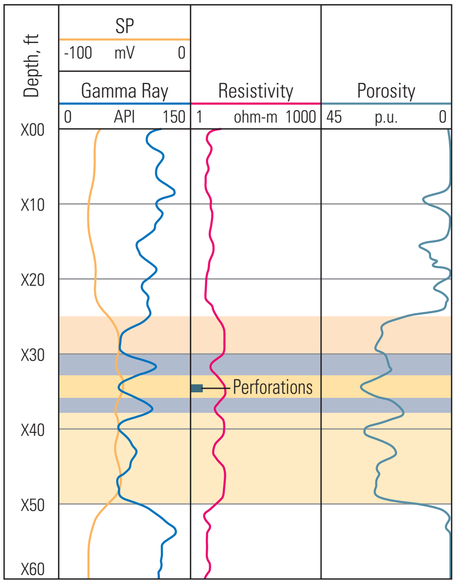
^ Comparison of the horizontal (*top*) and vertical (*bottom*) permeabilities measured by mini-DSTs, cores and IPTTs. The core data were averaged over each mini-DST test interval and converted to effective permeability using relative-permeability curves. Arithmetic averaging was used for horizontal permeabilities, and harmonic averaging for vertical permeabilities. The IPTT data are from the same tests as the mini-DSTs, but using two probes: V_1 at 2 m [6.6 ft] and V_2 at 4.45 m [14.6 ft] above the packer interval. The intervals tested are therefore different. In this case, the agreement between the different measurements is generally good.

Cased-Hole Mini-DSTs

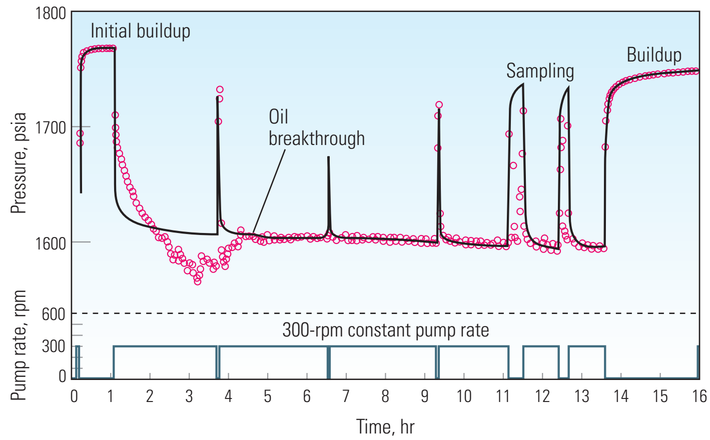
Phillips Petroleum, operating in the Peng Lai field offshore China, found that cased-hole mini-DSTs were a valuable complement to full DSTs and openhole WFTs in evaluating their reservoir.[19] Like many operators, they initially ran mini-DSTs to obtain high-quality PVT samples, but then found that the pressure-transient data contained valuable information. Peng Lai field consists of a series of stacked, unconsolidated sandstone reservoirs with heavy oil—11° to 21° API—of low gas/oil ratio (GOR), whose properties vary widely with depth. Testing each reservoir in each well with full DSTs was proving expensive, and was not always successful. Among other factors, the handling of the heavy oil at surface caused each DST to last between five and seven days. Large drawdowns, which were sometimes needed to lift the oil to surface, caused the formation to collapse and the near-wellbore pressure to drop below the bubblepoint. As a result, mini-DSTs were an attractive alternative for all but the largest zones.

With a probe, the drawdowns were too high, while unstable boreholes and high pressure differentials made openhole wireline testing with a dual-packer module risky. Phillips' answer was to run the dual packer in cased holes. By the end of 2000, they had performed 27 cased-hole mini-DSTs in seven wells. In one typical test, they identified a 3-ft low-resistivity zone that was isolated from the main reservoir at the well by thin shales above and below (next page, left). After cement isolation was checked, a 1-ft [30-cm] interval was perforated, and the MDT dual packers were set across it. Communication was established, and the formation fluid was pumped into the borehole until the oil fraction stabilized (next page, top right). Two oil samples were taken, and after an additional drawdown, a pressure buildup was recorded over 2 hours. The total testing time of 16 hours would normally be considered excessive and risky in openhole conditions, but presented no problem in cased hole.

The pressure derivative during buildup shows a short period of probable spherical flow followed by a period of radial flow (next page, bottom right). With initial values of k_s and k_h from flow-regime identification, the buildup data were matched with a limited-entry model, assuming a formation thickness of 3 ft with no outer boundaries. The match is excellent. The high horizontal permeability (2390 mD) and the low vertical permeability (6 mD) were not surprising for this zone. Overall, a zone that looked doubtful on logs proved not only to be oil-bearing but also to have excellent producibility.



^ Gamma ray, resistivity and porosity logs across a low-resistivity reservoir in the Peng Lai field, offshore China. The mini-DST was performed in a thin 3-ft zone that is isolated above and below by thin shale beds (gray) within a larger reservoir. Any oil found in this zone was expected to be about 13º API with high viscosity.



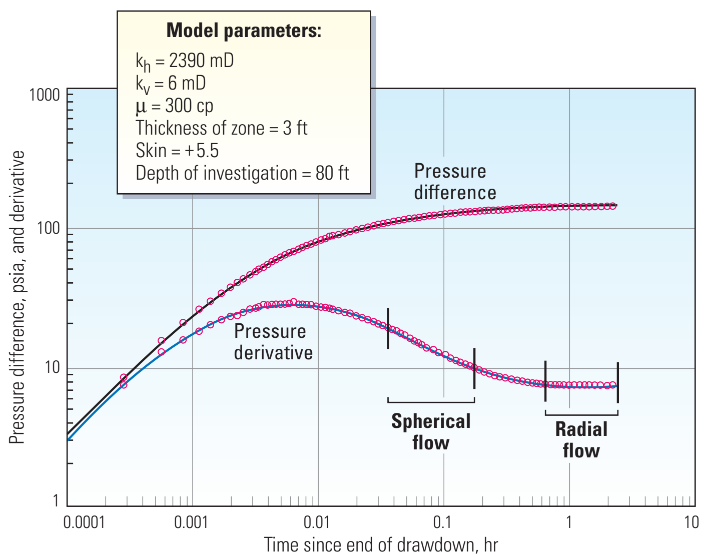
^ Pressure and pump rate during the cased-hole mini-DST from Peng Lai field. After communication was established with the formation, the pump withdrew invasion fluids until oil broke through. Once the oil fraction had stabilized (as measured by the OFA Optical Fluid Analyzer tool, not shown), two samples were taken. After one additional drawdown, a 2-hr buildup was recorded. Minimum drawdown pressure was 164 psi [1130 kPa], at or above the expected bubblepoint pressure, thereby avoiding free gas. The solid pressure line is the result predicted by the limited-entry model.

Mini-DST Limitations

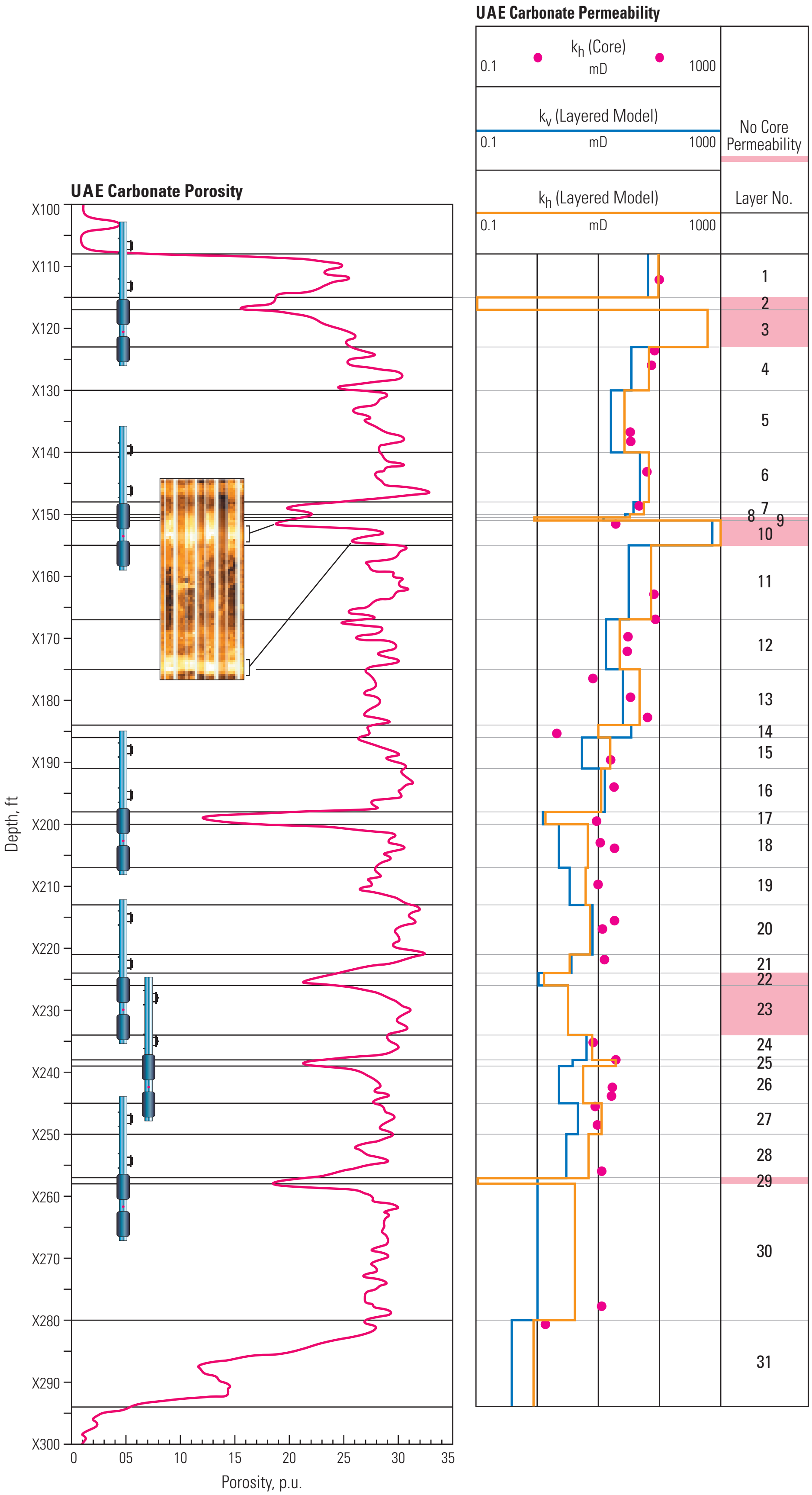
In spite of these good results, the permeability measurements have some limitations. The lack of an observation probe means that the only pressure transient comes from the pressure sink, which is affected by skin and tool storage. Both skin and storage influence the early part of the buildup and make identification of flow regimes and interpretation more difficult. Later in the buildup there needs to be the right combination of formation properties and bed thickness for significant periods of both spherical and radial flow to be observed. The radial-flow interpretation depends directly on identifying bed boundaries, while spherical-flow interpretation depends on knowing the storativity. Thus, it is difficult to determine both k_v and k_h simultaneously.

Finally, several factors can make a single transient hard to interpret. These include gas evolution near the wellbore, pressure and flow-rate variations due to continuous cleanup, and noisy drawdown pressures from pump strokes. Pressure measurements at observation probes are not usually affected by these phenomena. Since these probes are higher up the string, they also increase the volume investigated.

19. Hurst SM, McCoy TF and Hows MP: "Using the Cased Hole Formation Tester for Pressure Transient Analysis," paper SPE 63078, presented at the SPE Annual Technical Conference and Exhibition, Dallas, Texas, USA, October 1-4, 2000.



^ Pressure difference and derivative for the buildup at the end of the Peng Lai test. Spherical flow is identified by the slope of –0.5 on the derivative and radial flow by the slope of zero. The solid lines are the predictions of a limited-entry model using the parameters in the table.



IPTTs have proved to be an effective means for determining permeability distribution near the wellbore; in fact, they are the preferred method for layered systems. Mini-DSTs are usually run when the main objective is to recover a fluid sample, or to measure reservoir pressure, particularly in tight or heterogeneous formations. Permeability is an additional parameter with which to judge the producibility of the interval.

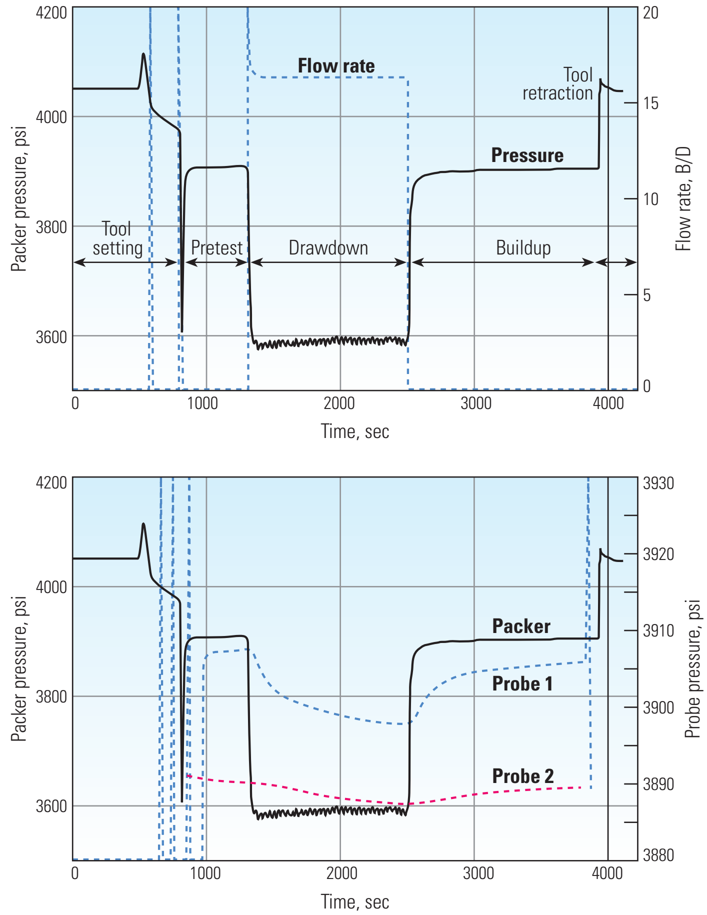
Interval Pressure-Transient Test

An IPTT run in a carbonate reservoir in the United Arab Emirates (UAE) illustrates the sequence of operations and methods employed in a full analysis.[20] This reservoir has distinct, contrasting layers that appear to extend over large areas. Reservoir management and the design of secondary-recovery schemes depend strongly on knowing the vertical and horizontal permeabilities and the communication between layers. In particular, the implementation of an injection scheme depends on the permeability of several low-porosity, stylolitic intervals. Will the stylolites act as baffles to injected fluid and severely affect sweep efficiency?

The stylolitic intervals may be thinner than 1 ft, but can be observed on logs and cores (left). However, their effectiveness as barriers is not clear. They can be correlated between wells, but their lateral continuity and permeability are uncertain. Cores could not be recovered from

20. Kuchuk FJ, Halford F, Hafez H and Zeybek M: "The Use of Vertical Interference Testing to Improve Reservoir Characterization," paper ADIPEC 0903, presented at the 9th Abu Dhabi International Petroleum Conference and Exhibition, Abu Dhabi, UAE, October 15-18, 2000.

< Log porosity in a layered carbonate (*left*). The low-porosity streaks are stylolites. The positions of the packer and the probes at each test location were chosen to straddle the stylolites. The right track shows the layered model used to interpret the IPTTs, with k_v and k_h from the model and k_h from core. Core permeability is generally too high and is either absent from the stylolites or fails to reflect the large contrasts seen by the IPTT. The FMI image (*left*) shows two low-porosity streaks (white) separated by a dark interval. The top streak is particularly patchy. The layered model used to match the IPTT showed that the top streak had higher k_v than k_h, while the center interval had very high permeability.



^ The sequence of events in a typical IPTT, as shown by the pressure and the flow rate recorded in the dual-packer interval (*top*). After tool setting, the pretest establishes communication with the reservoir by withdrawing up to 1000 cm^3 [60 $in.^3$] through the packer and 20 cm^3 [1.2 $in.^3$] through each probe. During drawdown, the flow rate is constant since it is controlled by the pumpout module. During the buildup period, the pressure is recorded for a sufficiently long time, approximately the same as the drawdown period, to ensure good pressure-transient data. At the end of the buildup period, the probes and packer are retracted. Packer and probe pressures were recorded with CQG Crystal Quartz Gauge pressure gauges during the IPTT (*bottom*). Note the much more sensitive scale for the probe pressures. Their final buildup pressure is lower because they are higher in the well. Note also the distinct delay in the start of the buildup on Probe 2, due to the low vertical permeability. The delay on Probe 1 cannot be seen at this time scale. The packer pressure is slightly noisy due to pump movement.

many of these intervals, and, in any case, give a very local value of the permeability. The operator decided to investigate the stylolites with a series of IPTTs in a new well. These could be recorded on a single trip in the hole, allowing the complete reservoir section to be tested efficiently.

An IPTT needs a minimum of one vertical observation probe and a sink, either a dual-probe or a dual-packer module. In this case, in order to sample more layers, the MDT tool was equipped with two vertical observation probes at 6.4 ft and 14.4 ft [1.95 and 4.4 m] above the center of the packer interval. The dual-packer module was chosen so as to generate a sufficiently large pressure change at the far probe. The pumpout module was used to withdraw formation fluids from each tested interval. Pressures were measured by quartz-crystal and strain gauges at both probes and packer.

Sequence of operations—Using openhole logs, the operator selected six test locations, with the depths chosen so that the stylolites lay between the dual packer and near probe. At each test location, the operator followed the same sequence of events: set the packers and probes, pretest probes and packer interval, drawdown, buildup, and retract packers and probes (above). The pretests measured formation pressure and established communication with the formation. Once communication was established, formation fluids were withdrawn through the packer interval at an almost constant rate for between 30 and 60 minutes. The rate was slightly different for each test, but remained between 15 and 21 B/D [2.4 and 3.3 m^3/d]. After each drawdown, the interval was shut in for another 30 to 60 minutes.

31-Layer Model

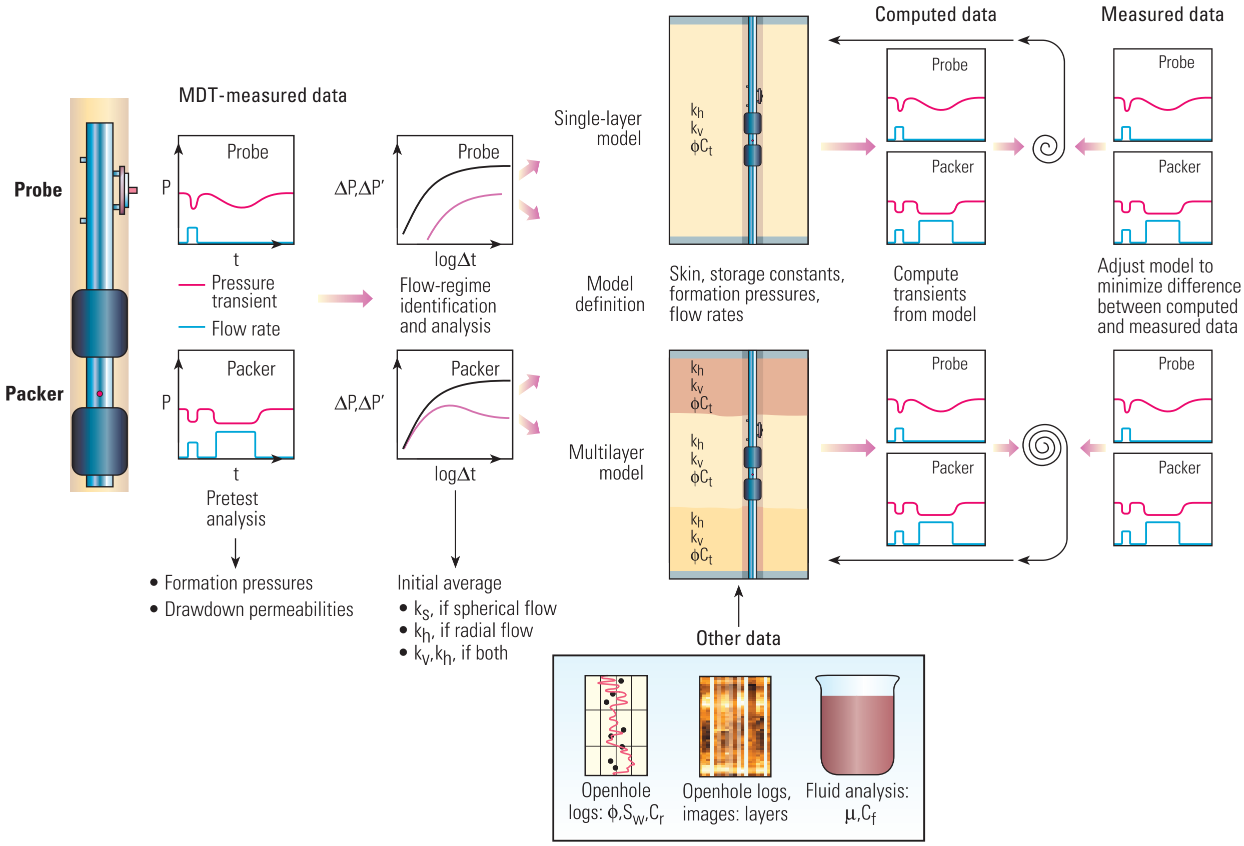
Layer	Thickness	Core k_h	k_h	k_v	Porosity	Confidence	Comments
Number	ft	mD	mD	mD			
1	7	97	98	65	0.21	low	
2	2	—	0.1	0.021	0.15	moderate	dense zone
3	6	—	610	610	0.27	high	high permeability
4	7	78	68	35	0.26	moderate	
5	10	33	26	16	0.28	low	
6	8	61	67	48	0.28	low	
7	2	46	53	39	0.18	low	
8	0.5	19	32	28	0.15	low	
9	0.5	—	0.9	11.1	0.14	moderate	patchy stylolite
10	4	—	1350	725	0.27	high	superpermeability
11	12	81	75	31	0.28	moderate	
12	8	30	24	14	0.26	low	
13	9	8-60	46	26	0.26	low	
14	2	2.7	9.9	33.8	0.2	low	patchy stylolite
15	5	16	15.6	5.4	0.29	high	
16	7	18	11.3	12.9	0.3	high	
17	2	9.3	1.4	1.3	0.11	high	dense zone
18	7	13	6.7	2.3	0.29	high	
19	6	9.4	6	3.5	0.28	high	
20	8	12.3	7.4	7.8	0.3	high	
21	3	12.1	3.3	3.5	0.25	high	
22	2	—	1.3	1.1	0.19	high	dense zone
23	8	—	3.2	3.2	0.2	high	
24	4	8.6	7.9	6.4	0.28	high	
25	1	19.1	19.8	3.8	0.2	high	patchy stylolite
26	6	16	5.4	2.3	0.28	high	
27	5	10	11.4	4.6	0.29	high	
28	7	11	6.8	3.1	0.28	high	
29	1	—	0.1	0.89	0.19	high	dense zone
30	22	11.3	4.2	1	0.28	high	
31	14	1.4	0.9	0.45	0.1	high	dense zone

^ Model with 31 layers used for interpreting pressure transients. Each layer is assigned a thickness, vertical and horizontal permeability, porosity, and level of confidence.

In this test, packer pressure dropped sharply by approximately 300 psi [2070 kPa], while near-probe pressure dropped more slowly by 10 psi [69 kPa] and far probe by 2 psi [14 kPa]. These responses give a first idea of permeability. The fact that there is a response at the vertical probes showed that there was communication across the stylolite.

Analysis—Interpretation starts with a look at each test independently. As with mini-DSTs, the first step is to analyze flow regimes. Buildups are preferred to drawdowns because they are less affected by near-wellbore factors, such as cleanup and pressure fluctuations caused by the pumpout piston. The interpreter examined each of the three pressure transients from the six tests, and established some initial estimates of permeability. Because of the highly stratified nature of this carbonate formation, these estimates were rough averages of the permeability near each station.

The heart of the interpretation is a realistic model, layered in this case, with permeabilities, porosities and thicknesses for 31 layers (above). Initial layer boundaries and thicknesses are determined from the logs, actually from high-resolution images since layers as thin as 0.5 ft [15 cm] may play an important role. Porosity and rock-framework compressibility are based on log data; fluid compressibility and viscosity come from fluid saturations and PVT analysis. Initial horizontal and vertical permeabilities are taken from the flow-regime analyses and other available sources—cores, logs and pretests. Initial estimates are also needed for tool storage and skin around the packer.[21] Finally, the flow rate during drawdown is an important input; in this case, it was measured and was taken to be essentially constant during most tests.



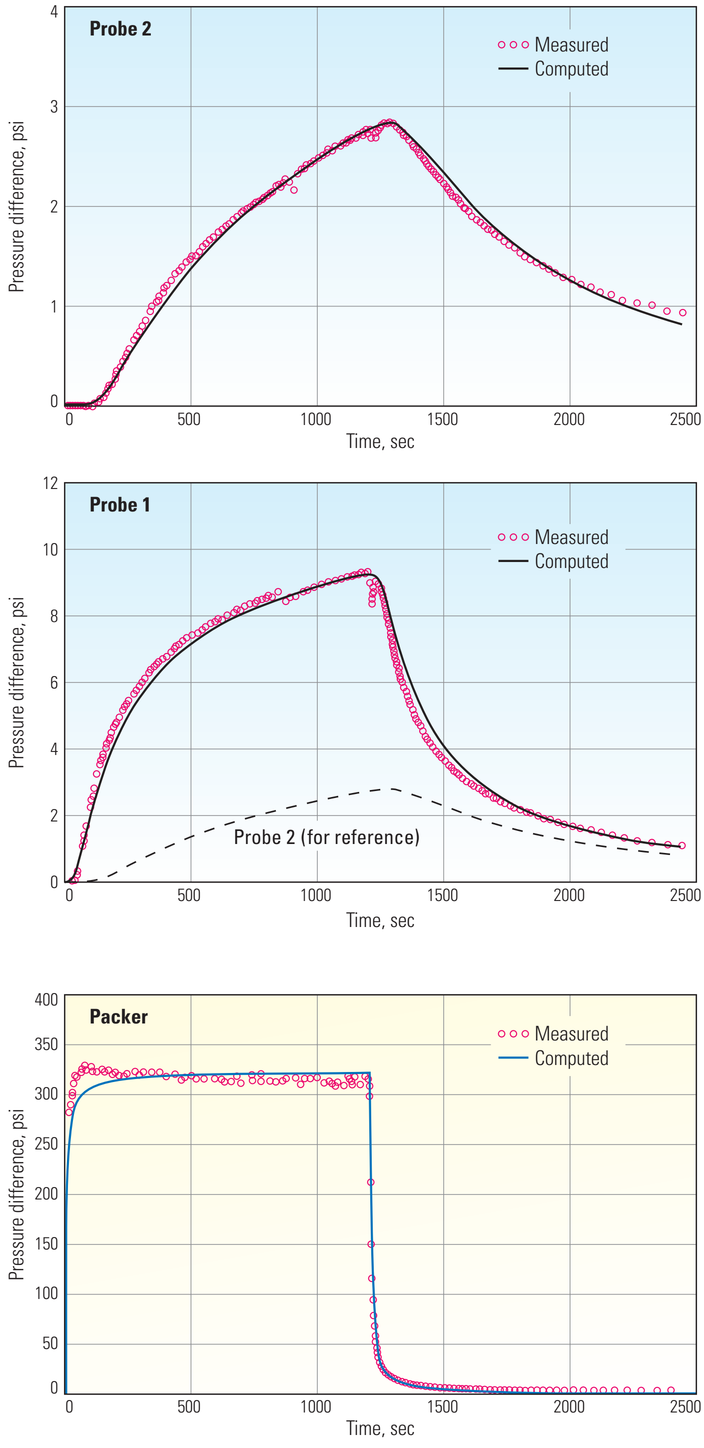
^ A typical workflow for the interpretation of an IPTT, with dual packer and one vertical probe. Each job is different, and the actual path taken depends on a trade-off between speed, complexity of problem and accuracy of results. Quickest, but least accurate results come from analyzing individual transients. Next may be analysis of all transients from one test with a single-layer model, then with a multilayer model. Adjusting the model to best match all the available data may require several iterations.

With these initial estimates, the expected pressure transients at the packer and the two probes are computed and compared with the measured transients during drawdown and buildup (above). An automatic optimization procedure adjusts the model parameters to minimize the differences over all transients. The main goal is to obtain the best k_v and k_h for the layers near the station. Bed boundaries are changed manually if necessary, while, in this case, ϕC_t was known well enough to be fixed. Permeabilities of layers away from the station may affect results to some extent but are not allowed to change significantly. Flow rate is held closely to the measured rate, but is still computed so as to allow for tool storage and the effect of small flow-rate changes on the transients.

When the results are not satisfactory, the geological model is reexamined with the geologist, redefining some layers and changing some initial estimates. Different weights can be applied to different time periods and different transients. For example, the packer drawdown period might receive less weight because, unlike observation-probe pressures, it is affected by the noise associated with production and variable cleanup.

The interpreter applied the model to each test in turn. However, this was not the end, since some tests were conducted close enough to each other that changing the parameters in the vicinity of one may have altered the results from another.

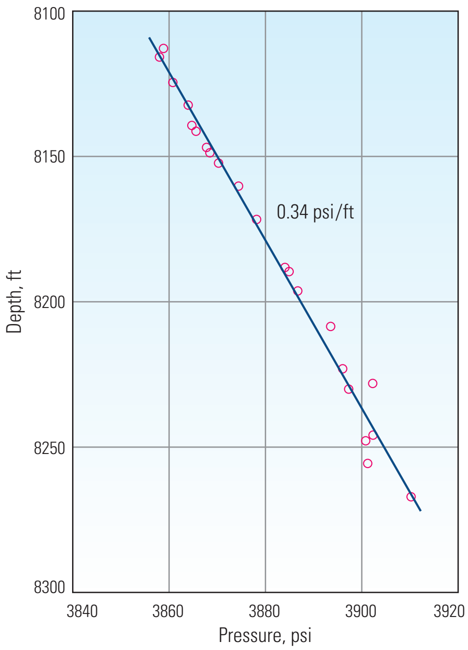
21. Since the flow rate into the probe is negligible, the skin and tool storage at the probe can be ignored.



^ A comparison between the measured pressure-transient response at the packer (*bottom*) and the two probes (*top and middle*), and the response computed from the layered model after nonlinear optimization of the parameters. The good agreement validates the parameters in the model. Other solutions may be possible, but were ruled out on the basis of other data.

Therefore, the optimized model was reapplied to each test so as to achieve a good match between all measured and computed transients (left). Some layers were better defined than others because there were more pressure transients in their vicinity. For this reason, the confidence factor for the bottom 15 layers, for which there were four tests, was higher than for the top 15, in which there were only two tests.

Results—Overall, the interpreter performed a type of history matching in which the reservoir model was iteratively adjusted to match 18 pressure transients distributed along the wellbore. The estimated permeabilities differed considerably from core permeability, being generally lower and varying by several orders of magnitude, from almost 0.02 mD to 1350 mD. No core-derived permeability measurements were available from intervals having these extreme values. On the other hand, the porosity varied little, except within stylolitic zones. As for most carbonate formations throughout the Middle East, porosity is not a good indicator of permeability. Of the six low-porosity intervals on the logs, only two had permeabilities below 1 mD. Two others were patchy with significant permeability, one with $k_v > k_h$ at X151 ft. In this particular test, the small pressure response at the probes (less than 0.5 psi [3.5 kPa]) could be explained only by a superpermeability layer between packer and probe. This surprising result was supported by an FMI image of the stylolite, which showed a conductive layer between two dense streaks, one of which had gaps in it (*figure, page 12*). None of this was apparent from the core data.



^ Pressure profile from MDT pretests across the reservoir. The pretests were taken at the packer and probes as part of each IPTT. The reservoir has been on production for nearly 20 years. After this much production, any barriers to pressure communication should cause the pressure gradient to be much less uniform. However, the lack of pressure barriers does not necessarily mean that fluids will flow vertically with ease.

The final model suggested that the layers should communicate over time. Pressure communication was confirmed by the formation pressure gradient from MDT pretests (left). The relatively uniform gradient showed that the stylolites did not act as pressure barriers. However, good pressure communication does not necessarily mean that fluids will flow uniformly through the reservoir. As the model showed, at least two high-permeability layers can act as conduits for injected water. This information has been used in the full-field reservoir simulator, and to examine unexpected water breakthroughs in production wells.

Mapping Stylolites

Carbonate rocks typically form in shallow, tropical marine environments. In some cases, a formation can extend for hundreds of miles. Carbonate sediments contain significant amounts of the metastable minerals aragonite and magnesium calcite; calcite itself is readily dissolved and reprecipitated by percolating pore fluids. Carbonate rocks are, therefore, likely to undergo dissolution, mineralogical replacement and recrystallization. These effects vary according to temperature, pore-fluid chemistry and pressure. Carbonate diagenesis commonly begins with marine cementation and boring by organisms at the sediment-water interface prior to burial. It continues through shallow burial with cementation, dissolution and recrystallization, and then deeper burial where dissolution processes, known as pressure solution, may form such features as stylolites and vugs (below).

The resulting diagenetically altered zones, whether of lower or higher permeability than the surrounding formation, are frequently extensive and affect large sections of a potential reservoir. For this reason, such features detected by borehole measurements often can be extrapolated some distance from the well.

The first IPTT example showed how the permeability of stylolites could be determined in a single well. The next question is how far the layers extend across the field. The depth of investigation of an IPTT depends on transmissivity ($k_h h/\mu$) and storativity, and varies with each test.

^ Large dissolution cavity. Although carbonates can have large dissolution cavities, they are not always as large as this.

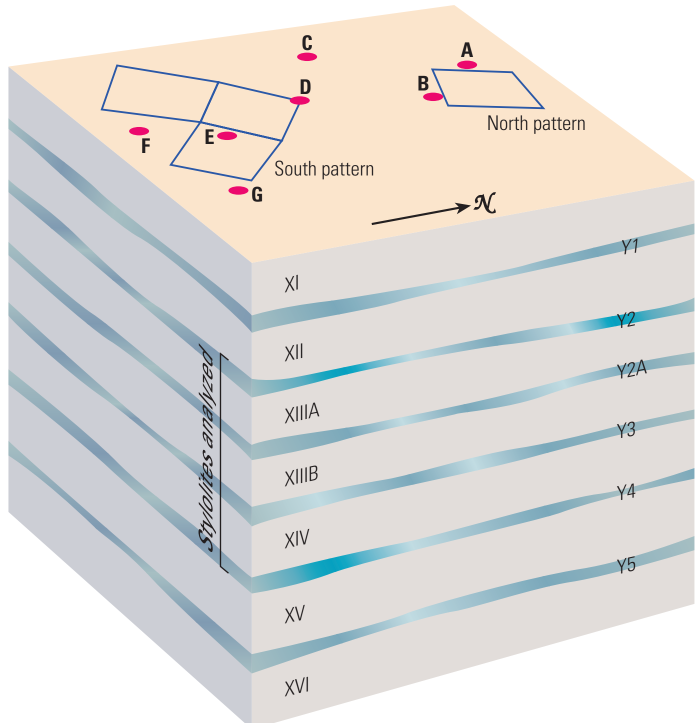
In the previous example, the depth of investigation ranged from about 20 to 30 feet [6 to 9 m]. The next example, from another field in the UAE, examines the lateral extent of barriers by running IPTTs in several adjacent wells (right).[22] The low-porosity, dense stylolites can be correlated easily between wells, but their actual density varies, so it is quite possible that their permeability also varies. The size and number of stylolites are observed to increase towards the flanks and toward one side of the field.

A total of 23 IPTTs was recorded in seven wells in two areas in which pilot gas-injection schemes were to be implemented. The main objective was to determine the vertical permeability of four stylolites—Y2, Y2A, Y3 and Y4.

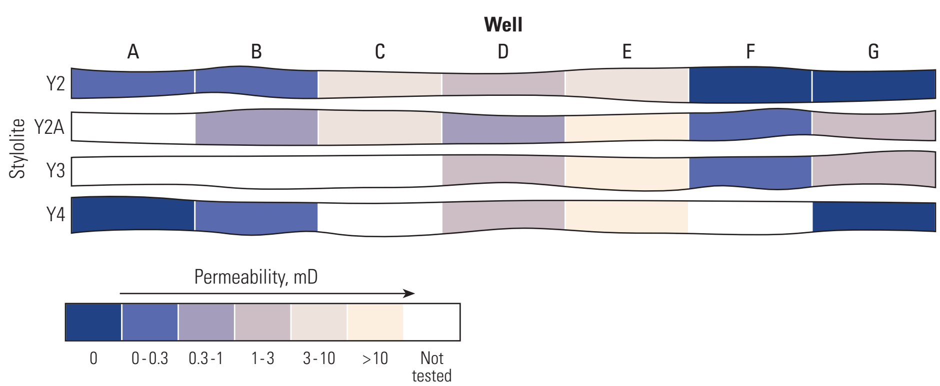
In this case, the MDT tool was configured with four probes (next page, top). A sink probe S creates the transient, which is measured by a horizontal observation probe H at the same depth but diametrically opposite the sink, and two observation probes V_1 and V_2 vertically displaced from the sink by 2.3 ft and 14.3 ft, [0.7 and 4.4 m]. With this configuration, the storativity, $\varnothing C_t$, need not be assumed in the permeability analysis, since it can be determined directly from the transients. An FMI image, recorded after the tests, clearly showed the imprint left by the probe assemblies on the borehole wall. The tool can be seen straddling two stylolites. In some tests, the flow-control module was used to give a constant flow rate. In others, formation fluids were withdrawn using the pumpout module for a longer test. Thus, as in the last example, a measured flow rate was generally available for each test.

In some tests, the sink probe could not withdraw fluids as it was set against a highly localized tight spot. In these cases, the operation was changed to withdraw fluids from the V_1 probe, using S and V_2 as the observation probes. More recently, interval tests in carbonates have been performed with the dual packer because its production interval is several thousand times that of a sink probe. Fluid withdrawal is then possible even with a high degree of heterogeneity and in relatively low permeabilities.

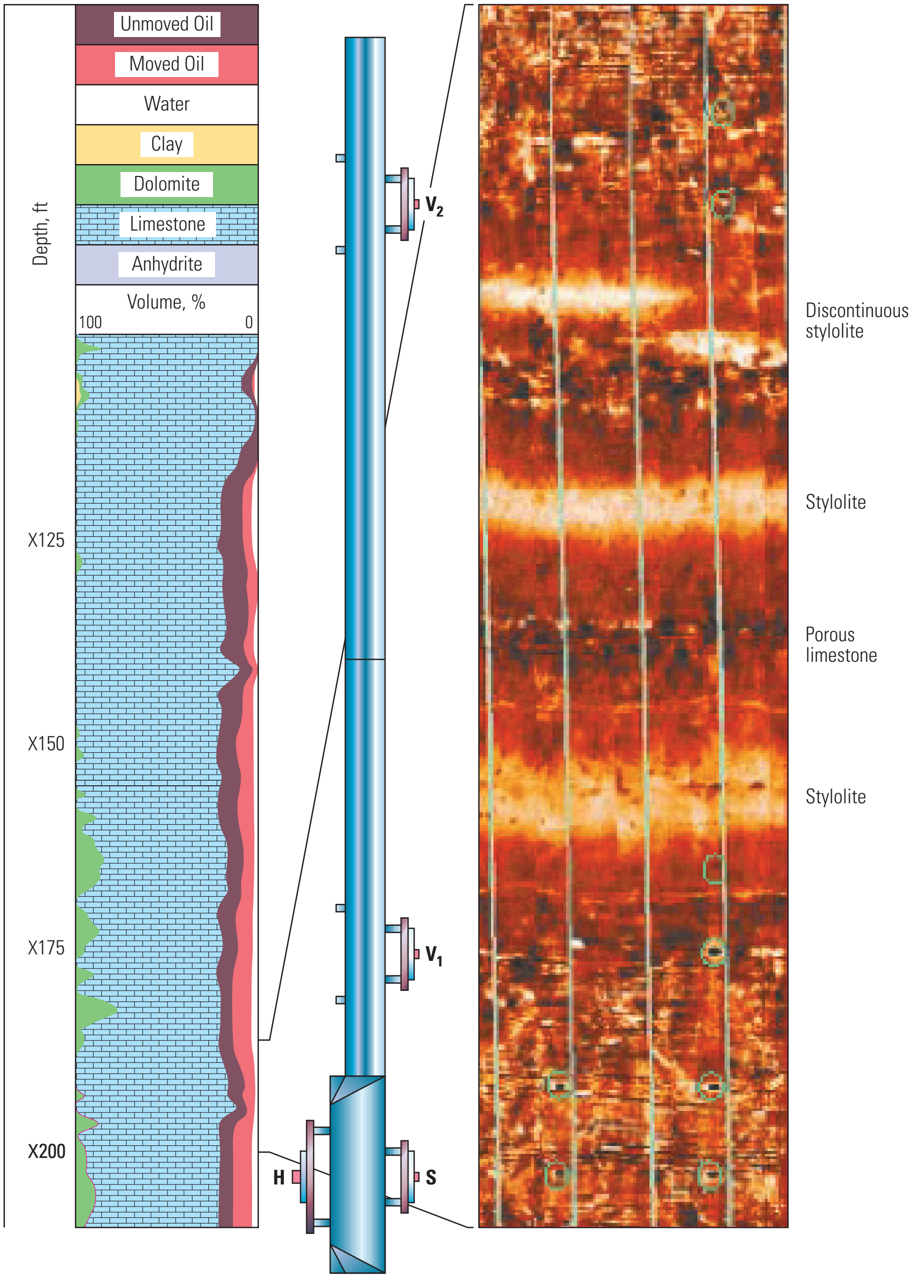
22. Badaam H, Al-Matroushi S, Young N, Ayan C, Mihcakan M and Kuchuk FJ: "Estimation of Formation Properties Using Multiprobe Formation Tester in Layered Reservoirs," paper SPE 49141, presented at the SPE Annual Technical Conference and Exhibition, New Orleans, Louisiana, USA, September 27-30, 1998.



^ Field with two pilot gas-injection schemes planned, one in the north, and the other in the south. The design depended heavily on the properties of the stylolites, Y1 through Y5. These zones could be easily identified on density logs and could also be correlated fairly easily across the reservoir. However, their properties varied, and it was not clear how effective they were as barriers to flow. IPTTs were recorded in seven wells (A through G) to quantify and map their properties correctly.



^ Vertical permeability of the four main stylolitic intervals as found by 23 IPTTs run in seven wells.

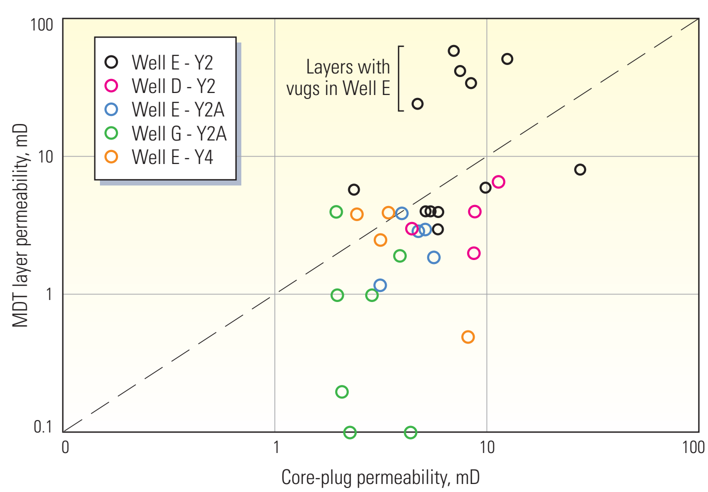


The interpretation began, as before, by flow-regime identification and analysis. Because of the large volume of data, each test was initially interpreted assuming a single homogeneous but anisotropic layer. This interpretation is quicker and gives an average k_h and k_h/k_v over some interval of reservoir rock containing the stylolite. Later, a more complete study was undertaken using a multilayer model as in the previous example.

The results showed considerable variation between the wells (previous page, bottom). In general, the stylolites were not absolute barriers to flow. For example, the Y2 stylolite was found to be a barrier in the south of the area, in Wells F and G, but very conductive in Well E. The Y2A stylolite was also very conductive in Well E. FMI images showed that the stylolite and its adjacent layers had a significant number of vugs, a feature not captured by the cores. Cores generally found a higher k_h than did the IPTT but missed the vuggy intervals entirely (below). The IPTT quantified the degree of hydraulic communication and allowed better planning of the pilot gasflood scheme.

< Volumetric analysis (*left*) and the four-probe MDT tool (*middle*) set across the Y3 stylolitic interval in Well F. The FMI image (*right*) was run after the tests and shows clearly the imprint (circled in green) of the four probe assemblies at two different tool locations.

> Comparison of k_h from core plugs with k_h from the corresponding layers of the IPTT interpretation. The core values were obtained by arithmetic averaging of the samples within the IPTT interval and by converting from absolute to effective permeability. In a perfect match, points would lie on the dotted line. Core-derived k_h is generally higher. The core data do not capture effectively the vuggy layers of Well E.

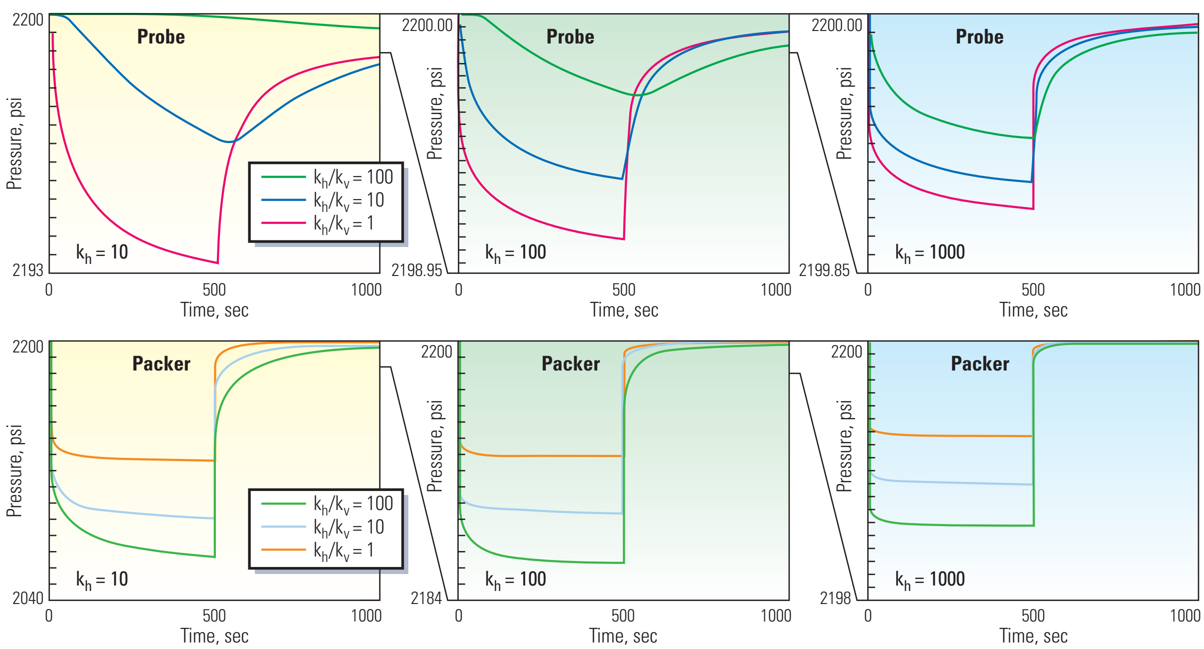


^ The Hassi Berkine South field in Algeria operated by Anadarko.

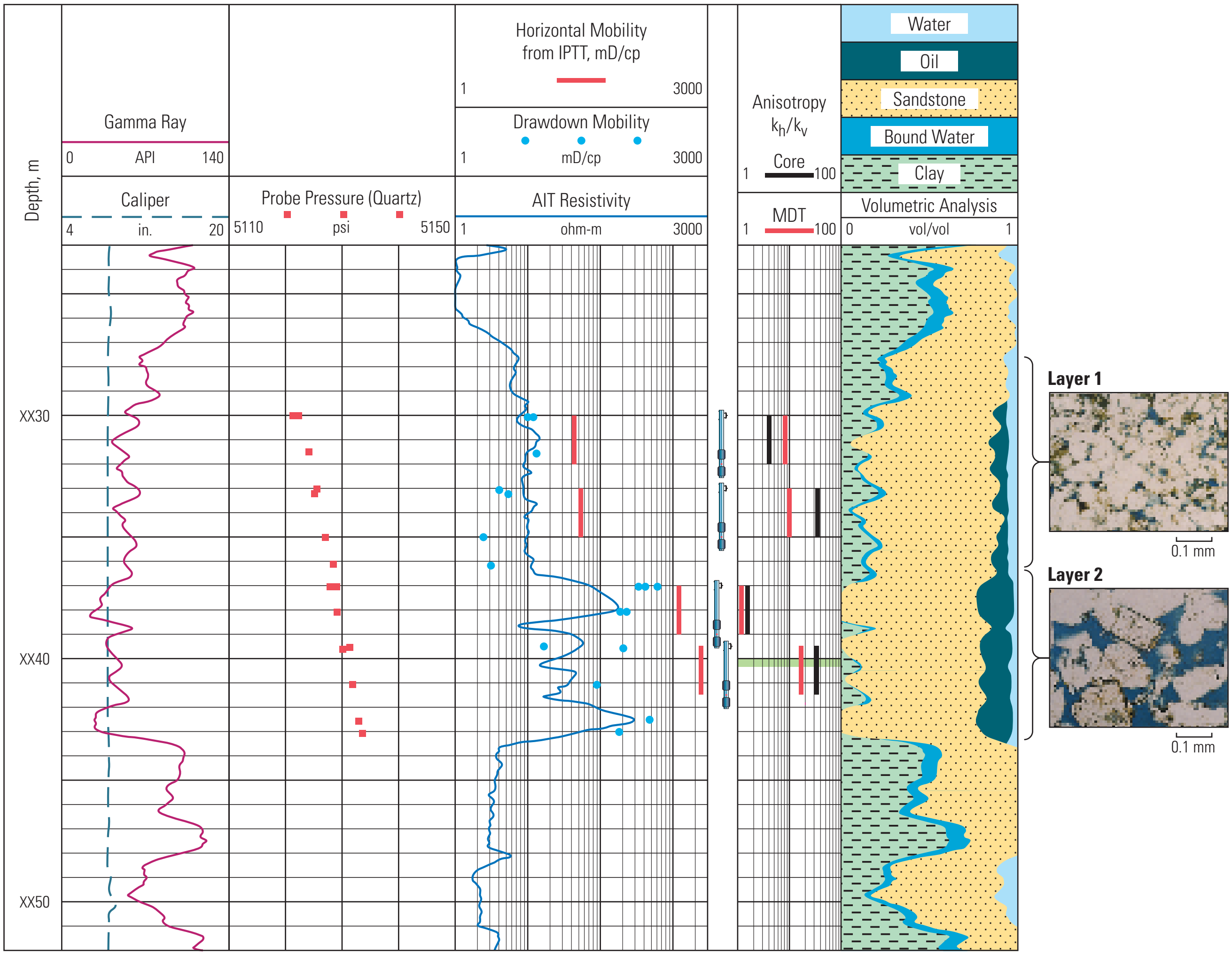
Anisotropy in Sandstones

Sandstones also pose questions about vertical permeability and barriers to flow. Anadarko Algeria's plans for the development of Hassi Berkine South field called for injection of both miscible gas/water and possibly water-alternating-gas (WAG) in the future (left). They needed to know the permeability anisotropy in the field to improve confidence in the vertical sweep efficiency, and in the recovery values being predicted from numerical models. This information was required early in the appraisal-drilling program as it affected decisions on facilities and infrastructure. The reservoir is in the Triassic Argilo-Gréseux Inferior (TAGI) sandstone.[23] The TAGI is fluvial in origin, with sands that are 5 to 15 m [15 to 50 ft] thick. The area of interest has two major rock types: a fine- to very fine-grained sand with interspersed shale laminae, and a fine- to medium-grained braided-stream deposit with discrete claystone layers (next page).

Upon reinjection, gas and water will be taken mainly by the high-permeability layers. It was important to determine the degree of gravity segregation expected in the TAGI, and the corresponding influence on vertical sweep, oil recovery and future production performance.



^ The pressure response at a dual packer and a vertical probe 6.6 ft [2 m] higher during a drawdown followed by a buildup modeled for different horizontal permeabilities and anisotropies, but the same flow rate. Note the expanding pressure scale for each plot from low k_h on the left to high k_h on the right. Higher k_h reduces the signal (causes a smaller pressure drop) at both packer and probe. Higher k_h/k_v reduces the signal at the probe but increases it at the packer. The response is complex and sometimes paradoxical. For example, at the end of a very long flow period, the pressure drop at the vertical probe depends only on k_h, while the drop at the dual packer depends on both k_h and anisotropy. Also, no signal at the vertical probe can mean that there is a layer of either zero or infinite permeability between it and the dual packer. These paradoxes partly explain why simple analytical solutions are not reliable.



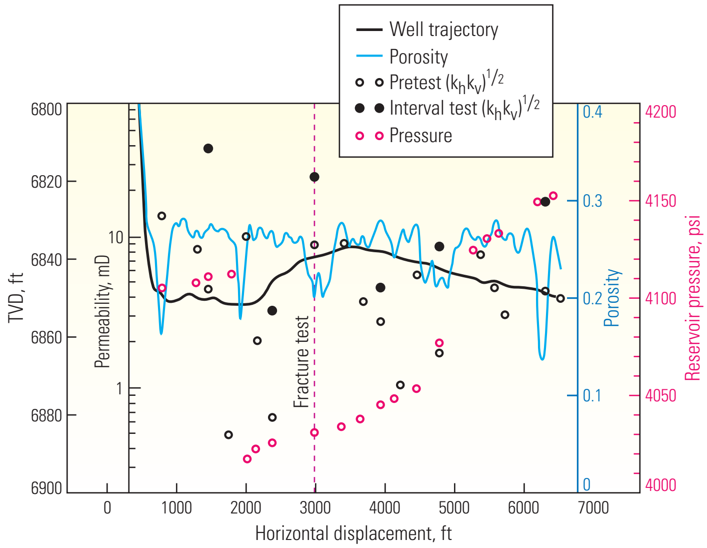
^ The two layers of the15-m TAGI sandstone. Layer 1 is fine-grained with shale laminations; Layer 2 is a medium-grained massive sandstone with thin claystone beds. The two IPTTs in Layer 1 both give horizontal mobilities below 100 mD/cp and moderate anisotropy. In Layer 2, both tests show high horizontal mobility, but the top test has low anisotropy, while the bottom test has high anisotropy, most likely due to the thin clay (green highlight in Track 4) at XX40.2 m between packer and probe. The average core anisotropy is similar, but slightly higher.

For the reservoir engineers simulating the gas injection, the most critical parameter was the anisotropy, k_h/k_v. They were not confident in the anisotropy from cores, around 10, as this value was unexpectedly low for such a depositional environment. The claystone layers were a particular worry since they seemed to extend across the field. An IPTT offered an attractive solution. It would test the anisotropy on a much larger scale than cores, and would provide permeability values at nearly the same vertical scale as the grid blocks used in the numerical simulation.

Four stations were planned—two in the fine-grained, lower resistivity layer; two in the medium-grained layer, one of which was designed to straddle a thin claystone. Permeabilities are high, so as part of the pretest planning it was important to check that sufficient pressure changes would be seen at the monitor probe. Using expected values for permeability and other parameters, simulations showed that if the flow-control and pumpout modules were used as flow-rate sources, the resulting pressure pulse at the monitor probe would be barely measurable (previous page, bottom). A higher flow rate, and hence a larger pressure response, could be obtained by flowing directly to a sample chamber. This is clearly desirable unless it draws gas out of solution or causes sanding. After further modeling and checking experience elsewhere, the operator ran tests with the dual packer connected directly to the sample chamber.

The interpreters analyzed each test with a single-layer model, treating the entire 15-m sandstone as one layer. With no flow-rate measurement available, a special approach to the analysis had to be taken. In this approach, the probe pressure transient is used to estimate k_v and k_h, while the packer transient is used to estimate the flow rate and packer-interval skin. Since the estimates are interdependent, it is necessary to iterate between the formation parameters at the probe and the flow rate and skin at the packer until the results converge.

23. Peffer J, O'Callaghan A and Pop J: "In-Situ Determination of Permeability Anisotropy and its Vertical Distribution—A Case Study," paper SPE 38942, presented at the SPE Annual Technical Conference and Exhibition, San Antonio, Texas, USA, October 5-8, 1997.



^ Reservoir pressure and permeability from the MDT tool in a horizontal well. Permeability is measured by both pretest drawdowns and interval pressure-transient tests, the latter being generally an order of magnitude higher. The pretest permeability may be low due to formation damage or because it is measuring the effective permeability to filtrate in a water-wet reservoir. Porosity is from openhole logs. Between 1765 and 5266 ft horizontal displacement, the pressure is significantly lower than elsewhere, indicating higher depletion and poorer pressure support from water injection in the reservoir.

The resulting permeabilities reflected the average properties of the formation near each station. The results near the top two stations were similar, with horizontal mobility (permeability/viscosity) near 50 mD/cp and anisotropy near 10. The bottom two stations lay in the medium-grained layer. They both showed high horizontal mobility, but while the third station was nearly isotropic, the fourth station showed a much higher k_h/k_v. Assuming that the third station defines the properties of the clean sandstone, it seems likely that the fourth station is affected by the thin clay at XX40.2 m, which lies between probe and packer. Assuming also that the clay acts as an impermeable disk lying around the wellbore, we can estimate its radius as 2 m [6.6 ft].[24] By this estimate, it is quite limited in extent.

The entire TAGI interval in this well was cored, with horizontal permeability measurements made on plugs every 15 to 30 cm [6 to 12 in.], and vertical permeabilities about every meter. When the core permeabilities were averaged over the 2-m interval of each MDT station, they compared well with MDT results, both indicating anisotropy less than 100.[25] When shale laminae or claystone beds are absent, the anisotropy is less than 10. These results were further supported by five whole-core samples from other wells in the field.

The MDT data were analyzed further with a two-layer model, the only multilayer model available at the time. The results were similar. Ideally, a model with at least five layers is needed to simulate the whole formation. However, in this case of relatively homogeneous formations, the operator obtained answers that were sufficiently fit for the purpose with the simpler single-layer model.

The MDT results increased confidence in the anisotropy values that reservoir engineers were using for numerical modeling, and thus also in the predicted performance of the planned injection scheme. In fact, the MDT-measured values were used directly in the simulator. The field has been on production since early 1998, producing in excess of 70,000,000 barrels [11,123,000 m^3]. The MDT-derived anisotropy values continue to be used in the simulator, since the history match between actual field performance and predictions from the simulator have been excellent. Although in this case the core anisotropy data proved to be broadly correct, the confirmation on a much larger scale was a key piece of information gathered during the appraisal of the field.

Horizontal Wells

Operators rarely acquire permeability data in horizontal wells for reservoir description. However, horizontal wells often fail to live up to expectation. Some of the many causes are related to reservoir heterogeneities. In one horizontal well, 6 IPTTs and 19 pretests were run to investigate why neighboring wells had performed below par (above).[26] Two major features were observed that could cause poor production—the variation in reservoir pressure, dropping by as much as 100 psi [689 kPa] in the middle of the well; and the variation in permeability from 5 to 50 mD for fairly constant porosity. Clearly, the middle interval has been more depleted and received less support from water injection into the reservoir. Upon completion, the middle interval is predicted to clean up less easily, while injection water will probably break through first at the toe, or end, of the well. For these reasons, it was recommended to complete the well with a casing.

IPTTs are particularly useful for evaluating the conductivity of faults and fractures in horizontal wells. Interpreting conventional well tests is difficult due to strong crossflow from pressure and permeability variations. Borehole images can determine the location of faults and fractures, and whether or not they are mineralized. In this well in a carbonate reservoir, images showed many vertical fractures but could not determine their hydraulic conductivities. Pressure differences indicated that while some were closed, others may have been open. Open fractures could harm production by quickly drawing water up into the well.

To test the fractures, the MDT tool was set with a dual-packer module straddling a set of fractures seen at 2983 ft (below). The logarithmic derivative with respect to Horner time for the buildup test at the packer location indicates a tool storage-dominated period that ends with a short slope of –1.0 at 0.015 hr. Following the storage period, the derivative exhibits a –0.5 slope spherical-flow regime until 0.15 hr, after which the derivative goes downward, indicating a higher permeability region. The probe buildup derivative also exhibits a short spherical-flow regime, though its value is lower than that of the packer test. The fact that the probe derivative is lower but ends at the same time at both packer and probe indicates a conductive fracture to the left of the probe. The fracture or fractures must either be short or have a finite conductivity because the derivative decreases only gradually. In addition, the best match to the transients was achieved with a positive skin—another indication that the fractures opposite the packer were not open.

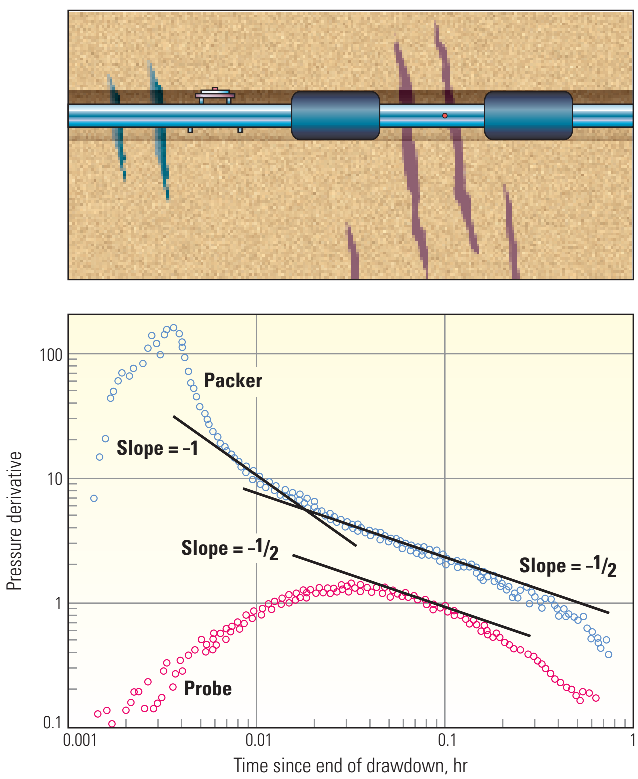
All the major fracture intervals were analyzed in this manner. The combination of fracture analysis, permeability and pressure data is of great use not just for predicting the performance of a particular well, but also for analyzing how the reservoir is responding to water injection and deciding whether to drill horizontal or vertical wells.

Conclusion

Operators are expanding their use of modern wireline formation testers to determine permeability and help make important well-completion and reservoir-management decisions. Compared with conventional cores and well tests, these testers provide cost-effective information at a scale intermediate between the two. This information is critical for evaluating the effect of reservoir heterogeneities, baffles and conduits.

Wireline formation testers measure permeability in different ways, depending on the hardware configuration. The mini-DST is particularly useful for evaluating small intervals at a fraction of the cost of a full well test. The interval pressure-transient test provides the most reliable and extensive permeability information from these tools. With recent developments in software and interpretation techniques, interval tests can now evaluate highly layered formations, horizontal wells, and even gas reservoirs.[27] The latter have often been considered too challenging because of the high compressibility and mobility of the fluid. In addition, the risk of sticking the tool—the fear of many operators—has been reduced through the use of risk-assessment software.[28]

Currently, engineers are seeking to improve results in formations with high mobilities, heavy oil or unconcolidated sands—all difficult but not impossible cases. Work continues on the perennial problem of scaling up from cores to tests, and of integrating interval-test results with other data. Attempts are being made to measure in situ the variation of effective permeability with water saturation, using the fluid fractions measured while sampling in combination with openhole logs and interval-test data. As long as reservoirs continue to be heterogeneous and permeability distribution remains an issue—both virtual certainties—wireline formation testers will be needed to evaluate them, and improvements will continue to be made. —JS/LS



^ Pressure derivatives from probe and packer transients (*bottom*) for the analysis of fractures in a horizontal well. The engineer set the dual-packer (*top*) astride a set of fractures that had been interpreted on FMI images (at 2983 ft, *see figure previous page*), and performed an IPTT. The probe derivative is less than the packer derivative, but spherical flow ends at the same time on both transients. These observations along with the positive skin are best explained if the fractures between the packers are not hydraulically conductive, and if there is a conductive fracture to the left of the probe.

24. Goode PA, Pop JJ and Murphy WF III: "Multiple-Probe Formation Testing and Vertical Reservoir Continuity," paper SPE 22738, presented at the SPE Annual Technical Conference and Exhibition, Dallas, Texas, USA, October 6-9, 1991.
25. A thickness-weighted arithmetic average was used for the horizontal permeability, and a thickness-weighted harmonic average for the vertical permeability.
26. Kuchuk FJ: "Interval Pressure Transient Testing with MDT Packer-Probe Module in Horizontal Wells," paper SPE 39523, presented at the SPE India Oil and Gas Conference and Exhibition, New Delhi, India, February 17-19, 1998.
27. Ayan C, Donovan M and Pitts AS: "Permeability and Anisotropy Determination in a Retrograde Gas Field to Assess Horizontal Well Performance," paper SPE 71811, presented at the Offshore Europe Conference, Aberdeen, Scotland, September 4-7, 2001.
28. Underhill WB, Moore L and Meeten GH: "Model-Based Sticking Risk Assessment for Wireline Formation Testing Tools in the U.S. Gulf Coast," paper SPE 48963, presented at the SPE Annual Technical Conference and Exhibition, New Orleans, Louisiana, USA, September 27-30, 1998.