Measuring Permeability Anisotropy: The Latest Approach

Knowing how fluids flow through a reservoir is fundamental to successful management of hydrocarbon reserves. Fluid flow is governed by the permeability distribution. The latest technique for measuring vertical and horizontal permeability uses a multiprobe wireline formation tester. Operated in open hole, this technique provides measurements before the completion is run allowing reservoir management to begin at the earliest stages of a field's development.

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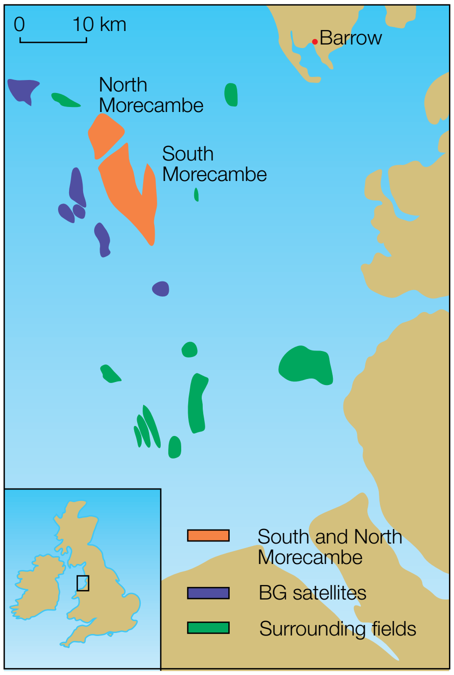
In this article, DSI (Dipole Shear Sonic Imager), MDT (Modular Formation Dynamics Tester) and RFT (Repeat Formation Tester) are marks of Schlumberger.

Permeability anisotropy in a sandstone. Thin layers of shale and quartz overgrowth block most of the vertical flow, making horizontal permeability much higher than the vertical permeability.

Permeability—the ease with which fluids flow through rock—has long been identified as one of the most important parameters controlling reservoir performance. Yet it is one of the most difficult to measure. If permeability were the same at all places and in all directions—homogeneous and isotropic—then measuring the flow through a sample of rock would reveal its value. However, rock type and grain size may vary through a reservoir leading to variation in permeability. To complicate matters further, measuring permeability parallel to layers of sedimentary rocks may give a different value to a perpendicular measurement (*left*). Therefore permeability measured at the same point in the horizontal direction, k_h, may be different from permeability measured in the vertical direction, k_v. This directional dependency on any type of measurement is called anisotropy. A measurement, such as vertical permeability, in the same direction at two distinct points may also be different. Positional dependency is called heterogeneity (*next page, bottom*). Needless to say, in the horizontal plane, horizontal permeability may have a maximum value, K_H and a minimum value, k_h. Although anisotropy strictly refers to the directional dependency of a measurement, the ratio k_v/k_h is often used to quantify permeability anisotropy.[1]

The anisotropic nature of permeability can affect any process in which a density difference exists between fluids, for example primary production below the bubblepoint, gas cycling, gas or water coning, waterfloods

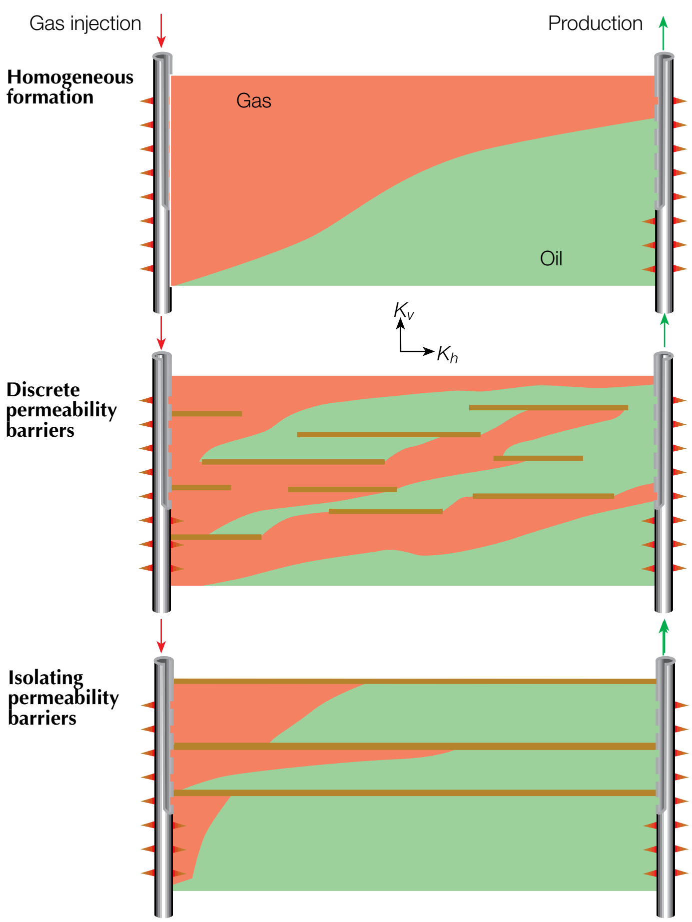


Satellites to the Morecambe gas fields in the Irish Sea.

and many steam processes. It can also influence injection and production rates if the anisotropy is severe. Completion and treatment strategies must also take anisotropy into account—for instance placing perforations near oil-water or oil-gas contacts.[2]

The experience of British Gas Exploration & Production Ltd. emphasizes the importance of anisotropy. The company discovered six small satellite fields of the Morecambe gas fields in the Irish Sea (*above*).[3] The Triassic Sherwood sandstone reservoirs found there are common to all the Morecambe fields and are typically 300 ft [91 m] thick. Underlying this is an extensive aquifer. Most fields have high permeability—horizontally 200 md, but with individual layers up to 18 darcies. Faults close the reservoirs on one or two sides, with dipping beds sealing the remainder.

To predict the rate and direction of water influx into the reservoir, vertical permeability must be measured. The amount of water influx will determine reserves and, therefore,



Effects of heterogeneity on recovery. Shale laminations affect the efficiency of a horizontal gas flood. In a homogeneous reservoir, the sweep efficiency is low (top)*. When the reservoir has discrete zones separated by permeability barriers, the efficiency is improved* (middle)*. Isolated permeability barriers lead to the most efficient sweep* (bottom)*.*

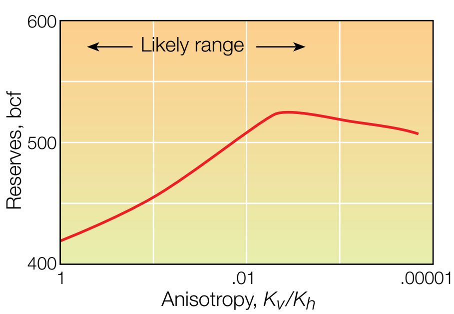
1. For a more complete discussion on the anisotropic nature of permeability: Ehlig-Economides C, Ebbs D, Fetkovich M and Meehan DN: "Factoring Anisotropy into Well Design," *Oilfield Review* 2, no. 4 (October 1990): 24-33.
2. Borling D, Chan K, Hughes T and Sydansk R: "Pushing Out the Oil with Conformance Control," *Oilfield Review* 6, no. 2 (April 1994): 44-58.
3. Wannell MJ, Colley NM and Halford FR: "The Use of a New Technique to Determine Permeability Anisotropy," paper SPE 26801, presented at the Offshore European Conference, Aberdeen, Scotland, September 7-10, 1993.

flow rate and revenue. Underestimating reserves will give a lower flow rate and influence project economics. Overestimating reserves will probably involve penalty payments on future gas sales contracts.

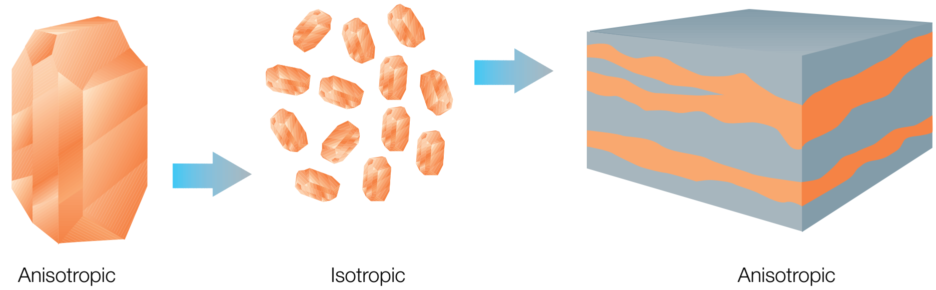
A modeling study by British Gas showed that at high values of anisotropy—high vertical permeability—considerable reserves are trapped behind the rising aquifer. At the other extreme, low anisotropy—low vertical permeability—does not allow recovery of gas from unperforated layers. Optimum recovery occurs when anisotropy is large enough to retard water influx, but still small enough to drain the unperforated layers (*below*).

Perforating policy for these fields will also be determined by anisotropy. If it is high, only the upper reservoir layers will be perforated to avoid water production. But high vertical permeability will allow drainage of unperforated layers. If anisotropy is low, more perforations will be needed to efficiently drain the field. Reperforating wells will probably be expensive as the likely development will use subsea platforms or those not normally manned. Hence the importance of measuring vertical permeability before perforating.

The problem is that anisotropy not only depends on direction, but also may vary with scale. For example, a single crystal may have an atomic structure that is anisotropic to properties such as electric current flow or acoustic propagation. But a piece of rock formed from randomly packed crystals may be isotropic to the same properties measured at a larger scale. At still larger scales, a series of isotropic rock layers, each with different values for these properties, will behave anisotropically (*above, right*).[4]



Changes in reserve estimates with permeability anisotropy for the Morecambe gas field. Modeling shows that high vertical permeability—high anisotropy—allows significant water influx from underlying aquifers in the Morecambe gas fields, dramatically reducing gas reserves. The amount of recoverable gas increases with decreasing anisotropy over the likely range of anisotropy values.



Anisotropy dependency on scale. Individual crystals of minerals are usually anisotropic, but a rock formed from a random distribution of crystals may be isotropic. At larger scales, layers of isotropic rocks—such as sediments—may be anisotropic.

The scale dependency of permeability anisotropy is illustrated by measurements taken by British Gas on its South Morecambe gas fields. Permeability measurements of 1-in. [2.5-cm] core plugs yield anisotropies of 0.5 to 0.3. However, vertical pressure profiles over a 400-ft [122-m] thick layer in the producing gas reservoir are consistent with anisotropies as small as 0.002.

Such extreme values are caused by layering of rock on a scale smaller than the scale of the measurement—each layer has a different value of permeability, but all contribute to the measurement. Two geological features in particular account for this type of anisotropy: crossbedding and shales (see "Oilfield Anisotropy: Its Origins and Electrical Characteristics," *page 48*).

Crossbedding is the alternate layering of sands of different grain sizes or textures at an acute angle to the major depositional features. There is little difference between the mineral composition of alternating layers.

Shales have small grain size and usually low permeability. Dispersed shale, for example platy illite which blocks pore space, reduces the permeability of most formations, but does not contribute significantly to anisotropy. On the other hand, shale layers reduce or eliminate flow to adjacent formations and therefore contribute significantly to the anisotropy at some scale.[5]

Anisotropy is also dependent on shale continuity. For example, a continuous shale may totally isolate one zone from another, in which case the permeability anisotropy measured across the shale will be zero. If, on the other hand, the shale extends only a short distance from the well, the two zones will not be isolated. Fluid will follow a long, tortuous path around the shale, effectively decreasing the permeability measured across it. So the extent of the shale controls the permeability across it.

Earlier we said that the ratio k_v/k_h is often used to quantify permeability anisotropy. A more accurate definition would be to call this ratio vertical permeability anisotropy, which is a useful concept for vertical wells where vertical permeability plays such an important role in field development. For horizontal wells, however, the permeability anisotropy in the horizontal plane becomes equally important (see "Permeability Anisotropy in Horizontal Wells," *page 28*). Horizontal permeability anisotropy is caused by the depositional environment or by fractures. Where natural fractures are oriented in one direction there will be a significant difference between the horizontal permeability measured, on a reservoir scale, in the direction of the fractures and that measured normal to them. When tectonic stresses are involved, permeability anisotropies may also occur, as microfractures, aligned with the direction of maximum horizontal stress, open up in the direction normal to the stress. It is also believed that stress anisotropy may cause minor permeability anisotropies without the presence of natural fractures by distorting the pore space.

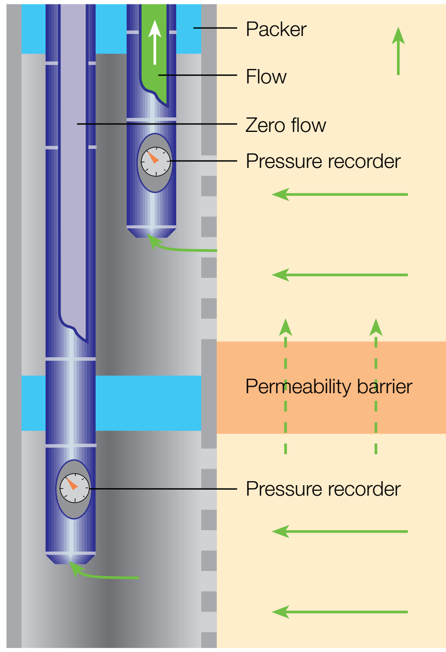
4. "Formation Anisotropy: Reckoning With its Effects," *Oilfield Review* 2, no. 1 (January 1990): 16-23.
5. Lake LW: "The Origins of Anisotropy," *Journal of Petroleum Technology* 40 (April 1988): 395-396.
6. Burns WA Jr.: "New Single-Well Test for Determining Vertical Permeability," *Journal of Petroleum Technology* 21 (June 1969): 743-752.
   Ehlig-Economides CA and Ayoub JA: "Vertical Interference Testing Across a Low-Permeability Zone," paper SPE 13251, presented at the 59th SPE Annual Technical Conference and Exhibition, Houston, Texas, USA, September 16-19, 1984.
7. Colley N, Ireland T, Reignier P, Richardson S, Joseph J, Zimmerman T, Traboulay I and Hastings A: "The MDT Tool: A Wireline Testing Breakthrough," *Oilfield Review* 4, no. 2 (April 1992): 58-65.
   Zimmerman T, MacInnis J, Hoppe J and Pop J: "Application of Emerging Wireline Formation Testing Technologies," paper OSEA 90105, presented at the 8th Offshore South East Asia Conference, Singapore, December 4-7, 1990.
   Head EL, Pop JJ and Bettis FE: "Reservoir Anisotropy Determination Using Multiple Probe Pressures," paper SPE 26048, presented at the SPE Western Regional Meeting, Anchorage, Alaska, USA, May 26-28 1993.
   Head EL and Bettis FE: "Reservoir Anisotropy Determination with Multiple Probe Pressures," *Journal of Petroleum Technology* 45 (December 1993): 1177-1184.

There are several different methods of obtaining permeability anisotropy, such as core analysis, well testing techniques and wireline formation tester measurements (see "Measuring Vertical Permeability," *page 30*). One well testing technique—vertical interference testing—is successfully used by a wireline formation tester.

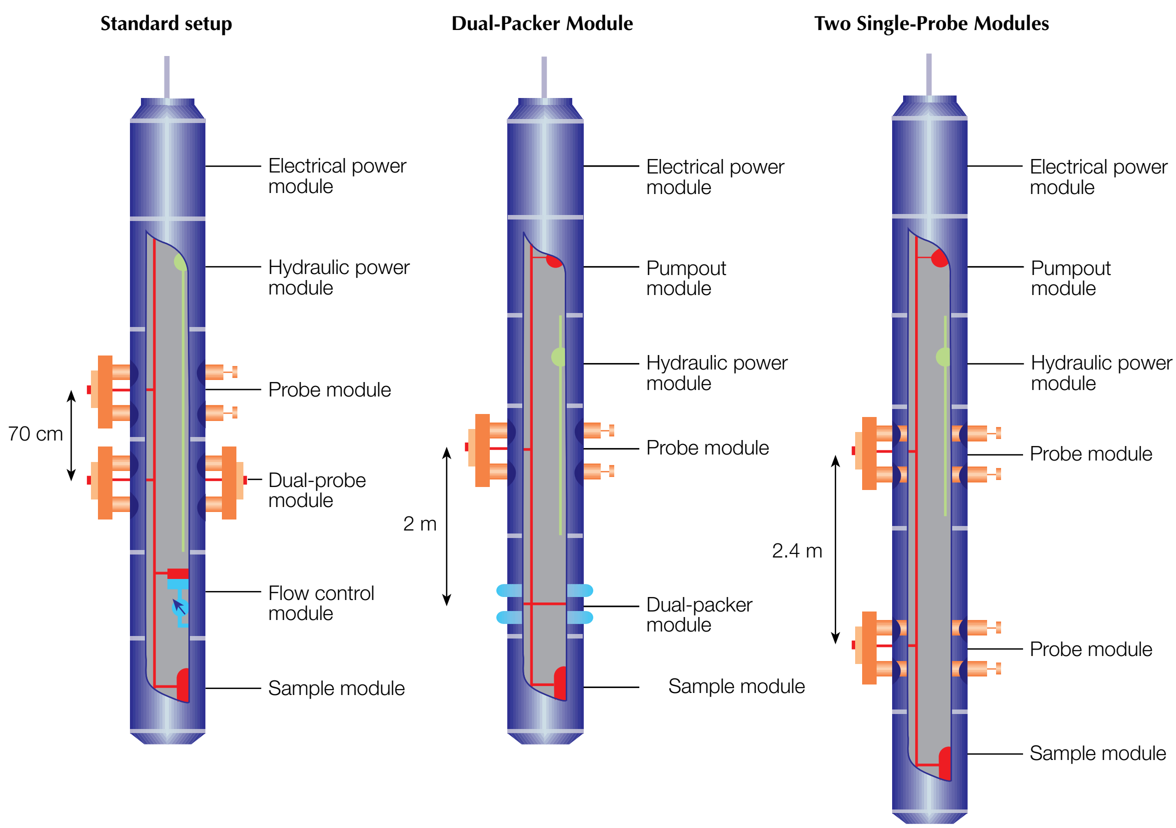
In vertical interference testing, a well is flowed at one zone, creating a pressure disturbance through the reservoir. The effects are recorded on pressure gauges some distance away at a second zone in the same well. The pressure response at the second zone depends on several factors: communication between the two zones, vertical and horizontal permeabilities, and reservoir boundaries. Transient analysis of the pressure response reveals horizontal and vertical permeabilities.

Vertical interference testing was first developed for well testing using two sets of perforations isolated by straddle packers (*left*).[6] This method relies on perfect isolation between the intervals being tested—good packer seals and no casing or cement leaks—and is costly if several zones are to be tested. However, the modular design of the MDT Modular Formation Dynamics Tester tool, using various combinations of probes and packers, allows openhole vertical interference tests to be performed faster and at lower cost—although on a smaller scale (*below*).[7]

British Gas used the MDT formation tester to perform five vertical interference tests.



Vertical interference test. The well is flowed through one set of perforations creating a pressure disturbance in the reservoir. If there is communication across an interval, a monitor pressure gauge at the second set of perforations will respond to the disturbance. The pressure response depends on the vertical permeability and the boundaries of the zone being tested.



MDT tool module combination for vertical interference testing. The standard setup** (left) **uses a single-probe module, dual-probe module and flow control module. The single probe and the horizontal probe of the dual-probe module are used as vertical and horizontal monitors, respectively. The flow control module regulates flow through the sink probe—the second probe of the dual-probe module—into a 1000-cm³ chamber to provide the pressure pulse. A dual-packer module** (center) **replaces the dual-probe module when probe plugging may be a problem. A sample chamber may be used to provide a larger pulse as the vertical monitor probe is farther away in this setup. Another alternative is to use two single-probe modules** (right). **This provides a longer spacing—8 ft [2.44 m]—between sink and monitor, than both the standard setup and dual-packer setup.

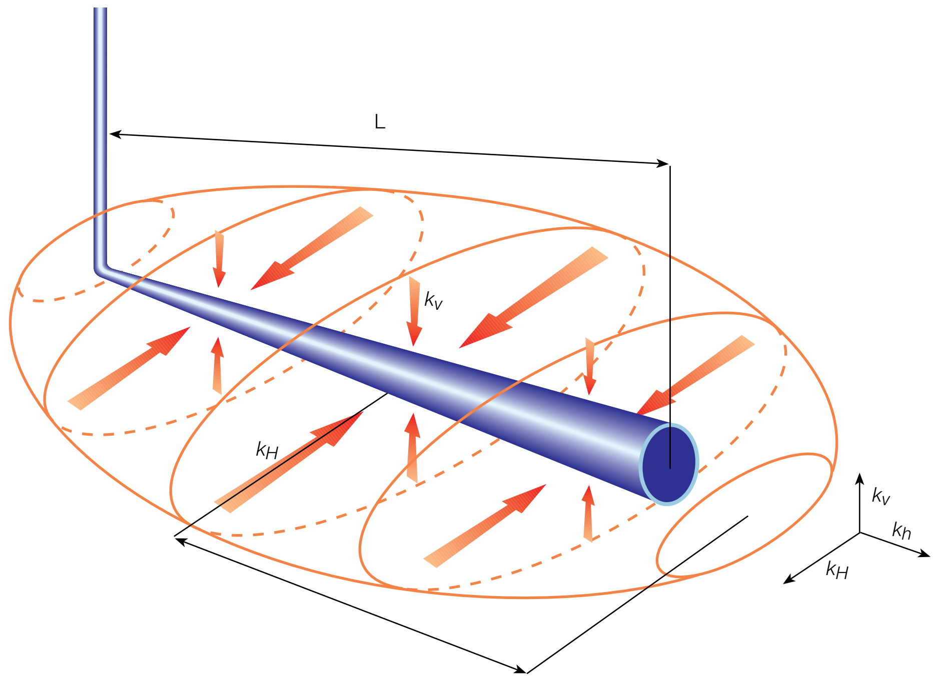
Permeability Anisotropy in Horizontal Wells

Horizontal wells are excellent producers for thin reservoirs—less than 50-ft [15-m] thick—or for thicker reservoirs with good vertical permeability. The drainage pattern for an ideal horizontal well is ellipsoidal and dominated by permeability anisotropy—the half axes are related to the length of the horizontal section, the horizontal permeability and the vertical permeability (right).

Vertical permeability anisotropy also affects production—the larger the anisotropy, the higher the productivity index. Low vertical permeability may make horizontal wells economically unattractive. Another important issue is the horizontal permeability anisotropy. A well drilled normal to the larger horizontal permeability will be a much better producer than one drilled in an arbitrary direction or normal to the smaller horizontal permeability. Therefore, it is important to measure permeability before the horizontal section is drilled.[1]

Most oil companies drill a vertical pilot hole to acquire as much data as possible about the target reservoir before drilling the horizontal section. These data may be used to optimize the horizontal segment length or even justify a decision not to drill the well at all.

One method of measuring vertical permeability is to perform a limited entry drillstem test after drilling the upper 10 ft [3 m] of the pilot hole into the reservoir (see "Measuring Vertical Permeability," page 30). Once the pilot hole is complete, other drillstem tests may be designed to confirm the results of the first test or to provide additional data such as fluid contacts or parameter estimates of additional layers.



□Horizontal well drainage pattern. The drainage pattern forms an ellipsoidal, which depends on the length of the horizontal section (L) and horizontal and vertical permeabilities. (Adapted from Economides MJ, Hill DA and Ehlig-Economides C, reference 1.)

An alternative procedure is to use the MDT formation tester tool. Although the depth of investigation is limited to a maximum of about 33 ft [10 m], the MDT tool has the advantage of operational efficiency. With test points carefully selected from openhole logs, the tool may provide data for subsequent well test interpretation. For example, many horizontal wells are drilled in layered reservoirs—each layer having different properties. A drillstem test conducted in the horizontal section of the well may require a layered reservoir model for analysis—a homogeneous model would lead to wrong estimates of critical parameters such as producing length, permeability and skin factor.[2] Parameter estimates, calculated for each layer from MDT tool data acquired in the pilot hole, would enable a layered reservoir model to be used.

Shear sonic logging measurements in the pilot hole may be used to identify the maximum and minimum horizontal stress directions. Usually, these coincide with the maximum and minimum horizontal permeability directions. A horizontal well should be drilled parallel to the direction of minimum horizontal permeability, which has the added advantage of offering the greatest borehole stability.[3]

Once the horizontal section is drilled, it is not too late to perform drillstem tests. However, the testing equipment needs to be flexible enough to

The tester configuration used a dual-packer module and a single-probe module. The dual-packer module employs two inflatable packers to isolate about 3.3 ft [1 m] of borehole and was used to create the pressure disturbance—the sink pulse. The single-probe module was mounted above to monitor pressure. The effective distance between the sink pulse and monitor probe was 6.5 ft [2 m]. Using a dual-packer module allowed high flow rates with limited pressure drop and also reduced sanding problems as the fluid velocity across the sand face is lower.

Prior modeling, using a range of vertical permeabilities, showed that the largest possible sink pulse would be required to generate a measurable pressure change across the 6.5-ft gap—the only limitation would be possible sand production. A 10,000-cm^3 sample chamber was used to generate the sink pulse and a high-precision quartz gauge was connected to the monitor probe. The plan was to flow the formation fluid into the sample chamber and monitor pressure at the monitor probe and between the packers. At the end of each test the pump-out module—also used to inflate the packers—could be used to empty the sample chamber.

The interpretation centers on the pressure transient measured at the vertical monitor probe. The amplitude of the pressure pulse originating at the dual-packer module determines the horizontal permeability, and the travel time gives the vertical permeability.[8]

Core	MDT Data		Core Data	
(ft)	k_v (md)	k_h (md)	k_v (md)	k_h (md)
X263	.60	80	0.0004	89.3
X242.9	0.45	55	0.77	35.8

Comparison of vertical interference test results with core data. At X263 feet, vertical permeability from core data is almost zero, indicating that the core contains a permeability barrier. The results from the MDT tester vertical interference test, however, show that the interval has reasonable vertical permeability. This may indicate that the barrier seen in the core data is not arealy extensive. At X242.9 feet, there is reasonable agreement between core data and MDT tester results.

Results showed that vertical permeability was between one and two orders of magnitude lower than horizontal permeability. Core measurements available at one depth agreed with the vertical interference tests. At another depth, the core data showed a much lower vertical permeability (*above*). The low-permeability layer seen by the core data may not be areally extensive, whereas the pressure response seen by the MDT formation tester sees beyond this—a distance of three to five times the sink to monitor probe spacing is typical—into the more permeable reservoir. This may account for the discrepancy and shows the significant impact the results have on reserves and development options.

Three-Probe Test in West Africa

Multiprobe vertical interference tests were conducted for AGIP Recherches Congo, West Africa, to measure permeability anisotropy and to identify permeability barriers across reservoir sections.

The tool configuration for the multiprobe formation tester consists of three probes:

- the sink probe—to induce a pressure pulse in the formation
- the vertical monitor probe located 2.3 ft [70 cm] above the sink probe and in the same vertical plane
- the horizontal monitor probe directly opposite the sink probe.

The monitor probes measure pressure transients induced at the sink probe. AGIP added sample chambers to this setup to recover clean, pressurized samples of formation water.

A typical sequence of events would be to position the tool and set all three probes

(continued on page 33)

8. Pop JJ, Badry RA, Morris CW, Wilkinson DJ, Tottrup P and Jonas JK: "Vertical Interference Testing With a Wireline-Conveyed Straddle-Packer Tool," paper SPE 26481, presented at the 68th SPE Annual Technical Conference and Exhibition, Houston, Texas, USA, October 3-6, 1993.

enter the horizontal section, otherwise it has to be set in the vertical part of the well. If this happens, wellbore storage may take so much time to dissipate that the part of the pressure transient used for estimating vertical permeability and skin—early-time radial flow—is masked.[4]

The MDT tool may also be used to measure permeability anisotropy in horizontal sections. The tool can be conveyed downhole into the horizontal section on drillpipe or by coiled tubing, and the probe orientation found using an inclinometry device. Mapping permeability variation along the well enables optimization of completion design, such as deciding where to place isolation packers or which sections of a cased hole to perforate.

1. Ehlig-Economides C, Ebbs D, Fetkovich M and Meehan DN: "Factoring Anisotropy into Well Design," *Oilfield Review* 2, no. 4 (October 1990): 24-33.

   Economides MJ, Hill DA and Ehlig-Economides C: *Petroleum Production Systems.* Englewood Cliffs, New Jersey, USA: PTR Prentice Hall (1994): 297-302.
2. Kuchuk FJ: "Pressure Behavior of Horizontal Wells in Multilayer Reservoirs with Crossflow," paper SPE 22731, presented at the 66th SPE Annual Technical Conference and Exhibition, Dallas, Texas, USA , October 6-9, 1991.

   Kuchuk FJ and Kader AS: "Pressure Behavior of Horizontal Wells in Heterogeneous Reservoirs," paper HWC94-25, presented at the Canadian SPE/CIM/CANMET International Conference on Recent Advances in Horizontal Well Applications, Calgary, Alberta, Canada, March 20-23, 1994.
3. For a detailed discussion on the relationship between stress anisotropy and permeability anisotropy:

   Ehlig-Economides et al, reference 1.

   Addis T, Last N, Boulter D, Roca-Ramisa L and Plumb R: "The Quest for Borehole Stability in the Cusiana Field, Colombia," *Oilfield Review* 5, no. 2/3 (April/July 1993): 33-44.
4. For more on testing:

   Clark G, Shah P, Deruyck B, Gupta DK and Sharma SK: "Horizontal Well Testing in India," *Oilfield Review* 2, no. 3 (July 1990): 64-67.

   Deruyck B, Ehlig-Economides C and Joseph J: "Testing Design and Analysis," *Oilfield Review* 4, no. 2 (April 1992): 28-45.

   Wellbore storage refers to the effects of fluid compressibility in the wellbore which dominate the first part of a pressure transient. The larger the amount of wellbore fluid involved, the longer these effects last.

   An assessment of skin damage is of great importance in a horizontal well to optimize any treatment program, such as acidizing.

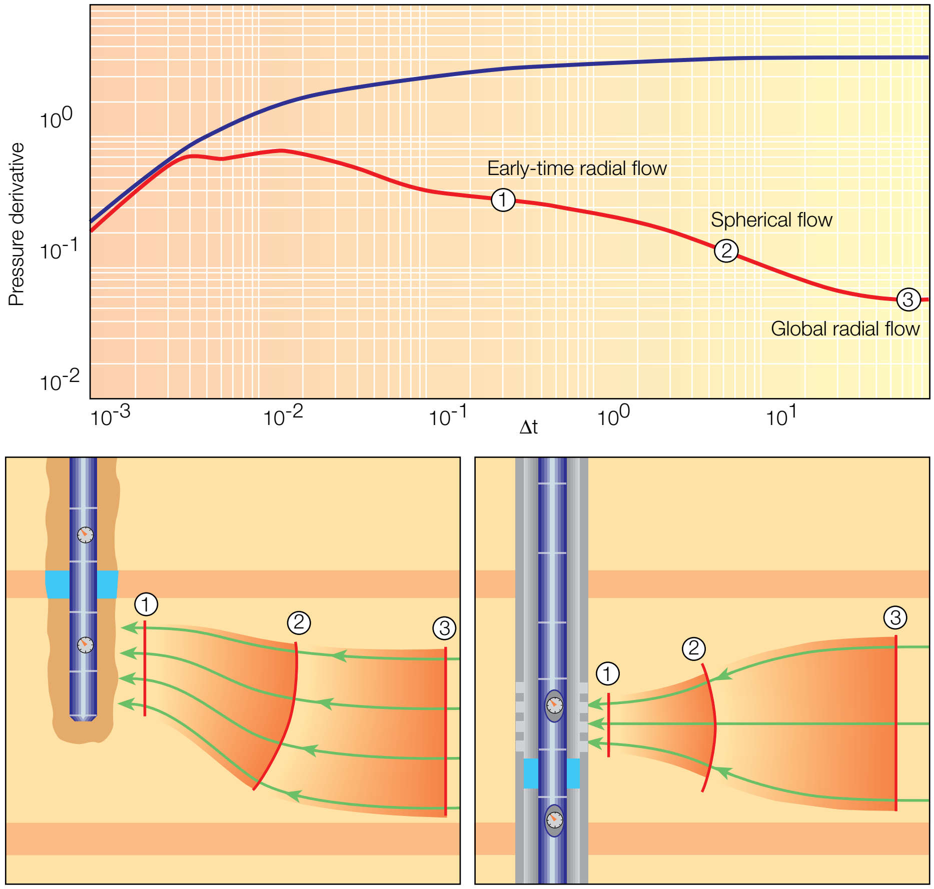
Measuring Vertical Permeability

In addition to vertical interference testing described on page 27, here are some other methods for measuring vertical permeability.[1]

Limited Entry Well Test

A well test records the pressure response to a pulse transmitted through the reservoir. One conducted on a well drilled partially into a reservoir or one where a limited portion of the reservoir is perforated—usually the upper portion—reveals three flow regimes (right).[2] **Once wellbore storage subsides, radial flow at the perforations is seen. Transient analysis of this portion of the pressure derivative is used to calculate horizontal permeability, k_h, at the perforations and also skin.**[3] **As the pressure wave propagates away from the well, the second regime, spherical flow, develops. The slope of the curve of pressure plotted versus the reciprocal of the square root of time curve allows calculation of spherical permeability. Spherical permeability, k_s, is the geometric mean of horizontal and vertical permeability, $\sqrt[3]{k_h^2 k_v}$. Hence vertical permeability and anisotropy may be determined. When the third regime—radial flow—develops far from the well, another value for horizontal permeability can be calculated.**

If permeability anisotropy is low—vertical permeability approaches horizontal permeability—then wellbore storage effects often mask the early-time radial flow. Spherical flow will also occur earlier and may also be masked.



□Partially penetrated well test. An openhole drillstem test performed in a partially penetrated reservoir *(bottom left)* or partially perforated well *(bottom right)*, reveals radial flow near the borehole (1). The flow regime develops into spherical flow (2) until the lower boundary is met. There radial flow once again develops (3). Horizontal permeability may be calculated from the radial flow regimes, and spherical permeability from the spherical flow regime. Spherical permeability is the geometric mean of horizontal and vertical permeabilities. Hence vertical permeability can be calculated.

1. Moran JH and Finklea EE: "Theoretical Analysis of Pressure Phenomena Associated with the Wireline Formation Tester," *Journal of Petroleum Technology* 14 (1962): 899-908.

   Arnold MD, Gonzalez HJ and Crawford PB: "Estimation of Reservoir Anisotropy from Production Data," *Journal of Petroleum Technology* 14 (1962): 909-912.

   Bourdarot G and Daviau F: "Vertical Permeability: Field Cases," paper SPE 19777, presented at the 64th SPE Annual Technical Conference and Exhibition, San Antonio, Texas, USA, October 8-11, 1989.

2. Raghavan R and Clark KK: "Vertical Permeability from Limited Entry Flow Tests in Thick Formations," paper SPE 4556, presented at the 48th SPE Annual Meeting, Las Vegas, Nevada, USA, September 30-October 3, 1973.

   Barnum RS and Frederick KA: "Vertical Permeability Determination from Pressure Buildup Tests in Partially Perforated Wells," paper SPE 20114, presented at the 1990 Permian Basin Oil and Gas Recovery Conference, Midland, Texas, USA, March 8-9, 1990.

3. Deruyck B, Ehlig-Economides C and Joseph J: "Testing Design and Analysis," *Oilfield Review* 4, no. 2 (April 1992): 28-45.

   Skin is a measure of the extra flowing pressure drop caused by near-wellbore damage.

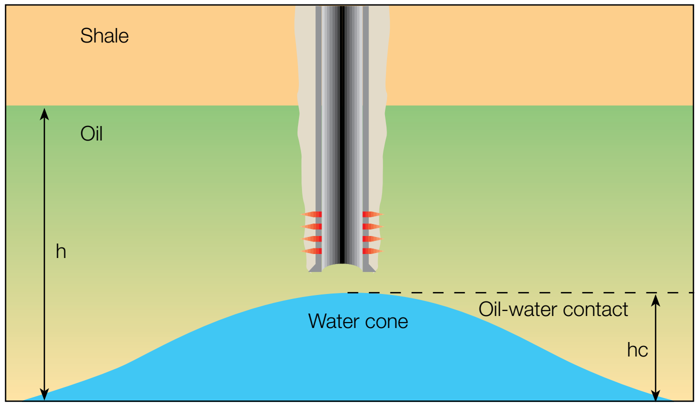
4. Bournazel C and Jeanson B: "Fast Water-Coning Evaluation Method," paper SPE 3628, presented at the 46th SPE Annual Meeting, New Orleans, Louisiana, USA, October 3-6, 1971.

5. Hollabaugh GR and Slotboom RA: "A Vertical Permeability Study," *SPE Journal* 12 (June 1972): 199-205.

   Arithmetic averaging applied to permeability means adding up all permeability measurements and dividing by the number of measurements. Harmonic averaging takes into account the distance over which that measurement applies. For example, a permeability of 1 md over 5 feet and one of 10 md over 1 foot would have an arithmetic average of 5.5 md, and a harmonic average of 2.5 md—the latter being a more realistic figure.

Water Coning Analysis

As a reservoir is produced, water or gas coning may develop. Although water or gas production is usually undesirable, records of when this occurs are useful for future field development. The height of a water cone in any particular well depends on flow rate and vertical permeability (right). The critical flow rate—above which water comes into the well—and the time taken to initiate water breakthrough are used to calculate vertical permeability.[4] These calculations may lead to adjustments of the reservoir model and influence plans for further field development.



Water coning. The height of a water cone (hc) depends on drawdown pressure and vertical permeability. By perforating close to the oil-water contact, a well may be used to monitor water breakthrough and hence, calculate vertical permeability.

Core Analysis

One of the more traditional ways of measuring permeability is directly on a sample of rock. Small plugs cut from cores are used—the orientation of the plug determines whether horizontal or vertical permeabilities are to be measured. After the core plug is cleaned with a solvent, brine is forced through the plug under constant pressure and the volume of emerging fluid is measured over a period of time. This gives the flow rate through the plug and hence, by Darcy's law, permeability.

If samples are taken frequently, say every 1 ft, then average values of permeability may be computed along the well. Usually harmonic averaging is made for vertical permeability to account for variations in vertical displacement between plugs. Arithmetic averaging is made for horizontal permeability unless horizontal displacement needs to be accounted for.[5] Results may be consistent with other ways of measuring permeability anisotropy provided that there is an absence of impermeable barriers, such as stylolites or shales. If these do occur, vertical permeability may be 10 to 100 times lower, making core data measurements unacceptable on a reservoir scale.

Formation Tester Pretests

Both single-probe and multiprobe formation testers check the integrity of packer seals when probes are set against the formation by performing a pretest for each. During a pretest, a small volume of fluid—20 cm^3 in the case of the RFT Repeat Formation Tester tool—is withdrawn from the formation. Transient pressure data are acquired and analyzed for drawdown and buildup mobilities.[6] In thick anisotropic formations, the effective permeability determined from such a pretest is the spherical permeability. But horizontal or vertical permeability must be known to calculate anisotropy from spherical permeability.

A full analysis requires knowledge of porosity, fluid compressibility and fluid viscosity. Because such a small volume of fluid is withdrawn from the reservoir during a pretest, the depth of investigation usually does not extend beyond the damaged zone. As a result, uncertainty arises over whether to use the compressibility and viscosity for mud filtrate or for formation fluid, assuming that these values are known in the first place. To add to these difficulties and limitations, the flow regime close to the probe may not be spherical and may be non-Darcy. Other problems, such as probe plugging, damage to the formation resulting from mechanical setting of a probe or gas evolution in the near-probe region, may invalidate the data before an interpretation can even be attempted.

Formation Tester Vertical Pressure Gradient

Formation tester pressure gradients recorded in depleted reservoirs highlight permeability barriers.[7] Under dynamic conditions, there is a component of pressure attributable to vertical flow, such as a rise in water level, within the reservoir. By measuring a dynamic pressure gradient and comparing this to the static pressure gradient—no production from the reservoir—this component can be estimated and the vertical permeability modeled.

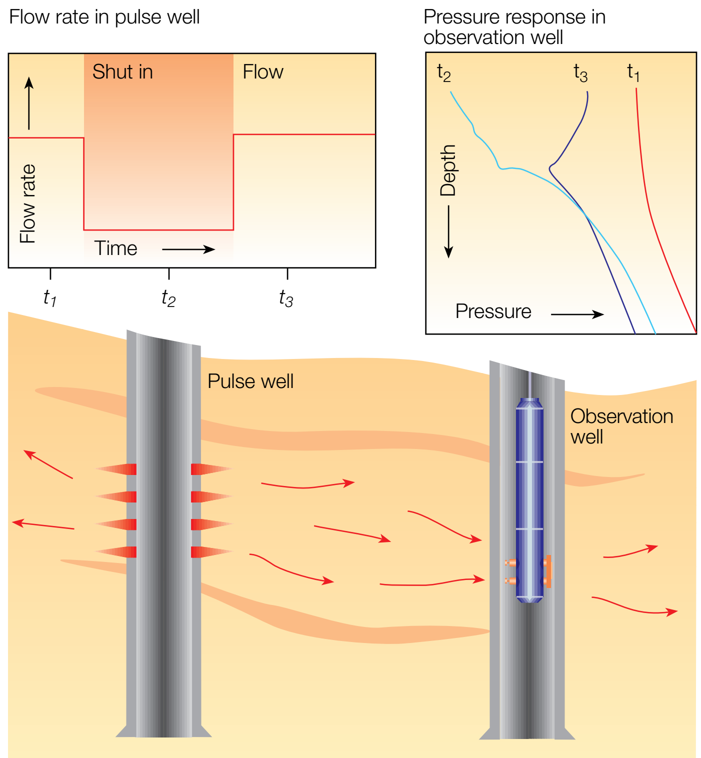
The main drawback of this method is the need for significant production before running the formation tester, so it is not possible to use this technique prior to field development. However, these data are extremely useful when infill drilling is considered later in a field's life.

6. Stewart G and Wittmann M: "Interpretation of the Pressure Response of the Repeat Formation Tester," paper SPE 8362, presented at the 54th SPE Annual Technical Conference and Exhibition, Las Vegas, Nevada, USA, September 23-26, 1979.

   Goode PA and Thambynayagam RKM: "Analytic Models for a Multiple Probe Formation Tester," paper SPE 20737, presented at the 65th SPE Annual Technical Conference and Exhibition, New Orleans, Louisiana, USA, September 23-26, 1990.

   Mobility is permeability divided by viscosity.

7. Stewart G and Ayestaran L: "The Interpretation of Vertical Pressure Gradients Measured at Observation Wells in Developed Reservoirs," paper SPE 11132, presented at the 57th SPE Annual Technical Conference and Exhibition, New Orleans, Louisiana, USA, September 26-29, 1982.

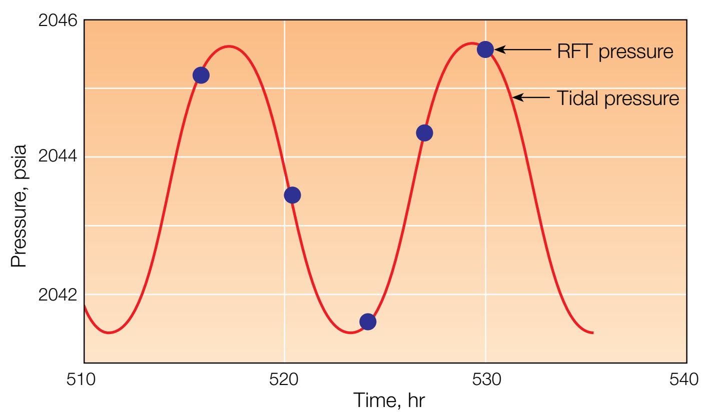


Formation tester pulse testing. Several pressure profiles are recorded in an observation well, while a producer or injector is alternately flowed and shut in. This produces pressure pulses that affect the profiles recorded in the observation well. These are influenced by the permeability distribution between the wells and any heterogeneities. Horizontal and vertical permeabilities are calculated by using 3D models and production history matching.

Formation Tester Pulse Testing

Better use of formation tester pressure profiles can be made with pulse testing. This consists of recording several profiles in an observation well at various stages while a nearby producer or injector is being shut in.[8] The act of shutting in the well generates a pressure pulse that will change the pressure profile at the observation well. These changes are affected by horizontal permeability between the wells and formation heterogeneities, such as faults and impermeable zones (right). Horizontal and vertical permeabilities are calculated using a three-dimensional (3D) reservoir model for pulse-test simulation and history matching.

Prior modeling is needed to estimate the duration of the pressure pulse and the timing of the pressure gradient surveys, but the results give permeability estimates over a length and scale comparable to the dimensions of the reservoir. However, the need for two wells and long flow periods makes this method uneconomical for predevelopment data collection.



Match between tidal and formation tester pressures. Pressure readings taken over a 12-hour period at the same depth are matched to the sinusoidal tidal pressure to provide a baseline calibration. Readings taken over the water-gas contact may then be used to calculate vertical permeability.

Tidal Pressure Changes

Gravitational attraction by the sun and moon causes the rise and fall of ocean tides. To a lesser extent, the earth's crust also deforms causing an earth tide. Ocean and earth tides induce small changes in reservoir pressure, although the mechanisms involved differ. Earth tides squeeze the reservoir, reducing its volume by about one part in one hundred million (10^{-8}). This causes a change in reservoir pressure. Ocean tides change the overburden pressure by reducing or increasing the head of water above the reservoir, directly changing the reservoir pressure. As the compressibility of gas is much greater than that of oil or water, the depth of a gas-liquid interface in a gas reservoir will move with pressure changes, forming a transition zone. The amount of movement is governed by vertical permeability over this zone. The length of the transition zone is measured by taking pressure readings with a formation tester. Pressures are taken regularly at several stations across the transition zone during a 12-hour tidal cycle (above, right).[9]

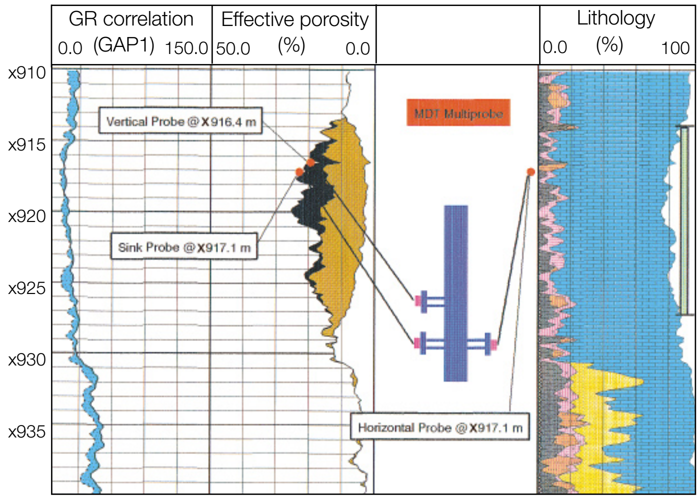
Because the pressure changes measured are small, a high-resolution quartz gauge is required. The method estimates the order of magnitude for vertical permeability and is best suited to offshore regions with significant tidal ranges.

8. Dake LP: "Application of the Repeat Formation Tester in Vertical and Horizontal Pulse Testing in the Middle Jurassic Brent Sands," paper 270, presented at the SPE European Petroleum Conference, London, England, October 25-28, 1982.
Lasseter T, Karakas M and Schweitzer J: "Interpreting an RFT-Measured Pulse Test with a Three-Dimensional Simulator," *SPE Formation Evaluation* 3 (March 1988): 139-146.
9. Wannell MJ and Morrison SJ: "Vertical Permeability Measurement in New Reservoirs Using Tidal Pressure Changes," paper SPE 20532, presented at the 65th SPE Annual Technical Conference and Exhibition, New Orleans, Louisiana, USA, September 23-26, 1990.

against the formation *(right)*, (see box "Defining the Test Intervals," *below*). The integrity of each probe packer seal is checked by performing a small-volume drawdown test—a pretest. A good seal for a probe set in a permeable zone is indicated by a pressure response showing a drawdown followed by a buildup to formation pressure. Similar responses at all three probes are required before the interference test is allowed to proceed. The transient pressure data from pretests may be analyzed to obtain local permeability estimates as with previous formation testers.[9]

It is advantageous—but not necessary—to have a constant flow rate during an interference test, and this is achieved by the flow control module. Up to 1000 cm^3 of fluid may be withdrawn from the formation at a specified flow rate during a test through either the sink probe or the vertical monitor probe—both are connected to the flowline that runs through most MDT tool modules. The flow control module chamber is reset after the test, emptying the contents into the borehole—using the pumpout module—or into a large sample chamber.

Flowing pressure at the probe must be at least 30% of the mud pressure for the flow control module to operate. In some cases, as in depleted or low-permeability formations, the pressure may be too low to sustain a flow rate. An alternative method is to open the sink probe to a sample chamber attached to the tool and estimate the flow rate. One of the AGIP tests was repeated by opening the sink probe directly to a 1-gallon [3800-cm^3] sample chamber, so that the two methods of providing a pressure pulse could be compared.



Position of MDT tool probes shown on the openhole log interpretation for one test.

Interpretation begins as tests are recorded. Communication is indicated by pressure changes at the monitor probes in response to the pressure pulse. The degree of communication is indicated by the magnitude of the pressure drop. The pressure drops at the horizontal and vertical probes provide a quick estimate of anisotropy.

Values of horizontal and vertical permeabilities come from transient analysis.[10] Transient analysis involves identifying when spherical or radial flow regimes occur, choosing the location of zone boundaries from openhole logs in such a way as to be compatible with the indicated flow regimes, and, finally, estimating reservoir parameters during those flow regimes.[11]

One method of identifying the flow regimes present employs pressure derivative plots for which a prerequisite is the flow rate history. The interpretation of flow regimes then proceeds in a similar fashion to that during the interpretation of a well test.[12]

When the flow rate is unknown, an alternative method may be used. It relies on the fact that multiprobe testing measures pressure transients at two distinct locations away from the sink. Fluctuations in flow rate will influence the two pressure transient measurements in some related way. The relationship is purely a function of the flow geometry and rock and fluid properties. This

9. Stewart G and Wittmann M: "Interpretation of the Pressure Response of the Repeat Formation Tester," paper SPE 8362, presented at the 54th SPE Annual Technical Conference and Exhibition, Las Vegas, Nevada, USA, September 23-26, 1979.

 If pretests show a return to hydrostatic pressure, no packer seal has been achieved. Other cases might show close to zero pressure indicating that a probe had hit a tight streak. In both cases, the probes would be retracted and the tool repositioned for a further attempt.

10. Goode PA and Thambynayagam RKM: "Analytic Models for a Multiple Probe Formation Tester," paper SPE 20737, presented at the 65th SPE Annual Technical Conference and Exhibition, New Orleans, Louisiana, USA, September 23-26, 1990.

11. Spherical flow describes flow towards a point coming from all directions, as if from the inner surface of a sphere. Radial flow describes flow towards a line as if coming from the inner surface of a cylinder. Spherical flow towards a point, such as the probe of a formation tester, will develop into radial flow, farther away from the point, as upper and lower boundaries of a producing zone are reached, forming the top and bottom of the cylinder.

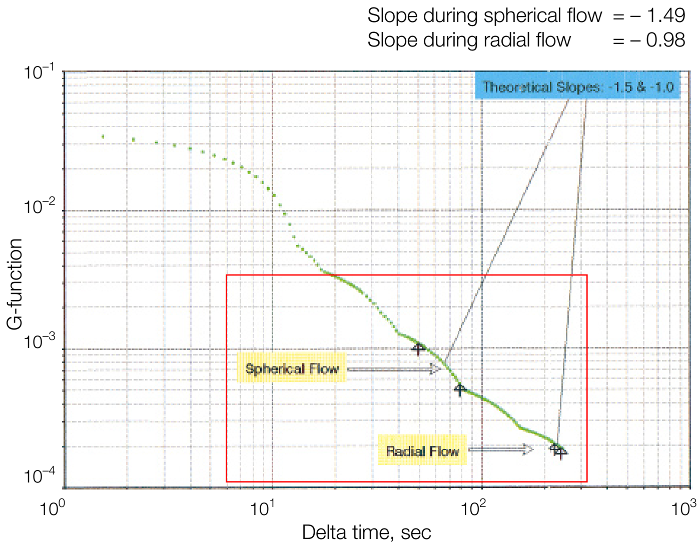
12. Bourdet D, Ayoub JA and Pirard YM: "Use of Pressure Derivative in Well Test Interpretation," paper SPE 12777, presented at the 1984 SPE California Regional Meeting, Long Beach, California, USA, April 11-13, 1984.

Defining the Test Intervals

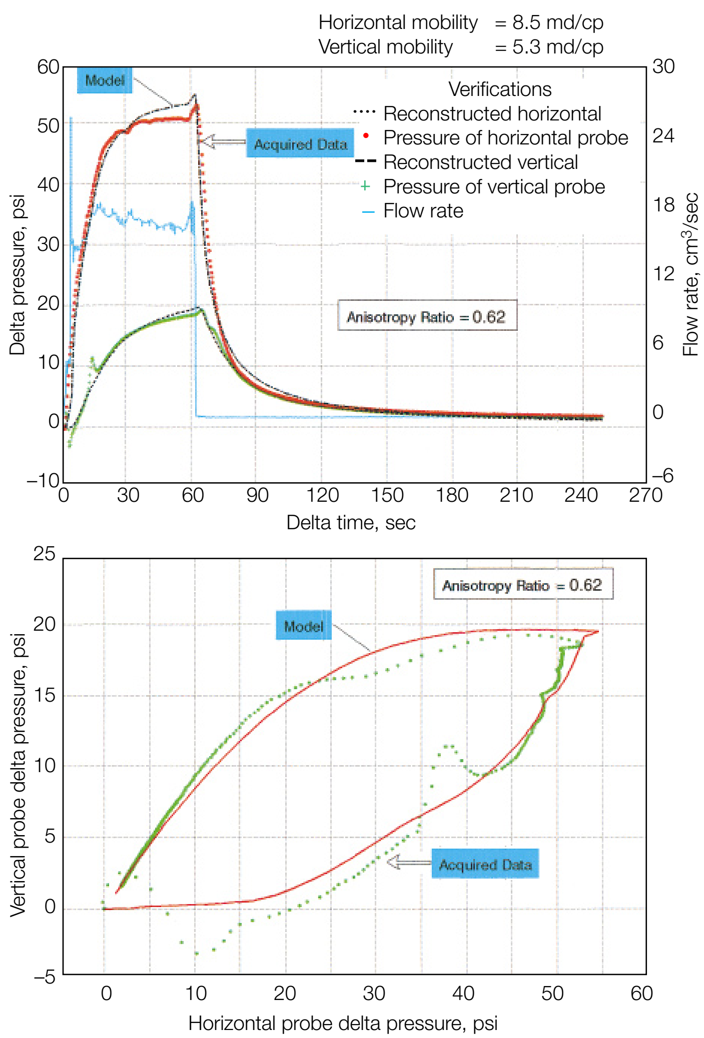
Before vertical interference tests are performed, as much information as possible must be gathered to accurately define the test intervals. Openhole wireline logs provide petrophysical information, such as porosity and fluid saturations, to define likely test zones. Geological logs—dipmeters and borehole images—help describe the depositional environment and likely reservoir structure. They also provide the fine detail required to accurately position the formation tester across potential permeability barriers. Images run after testing often show impressions left behind by formation tester probes confirming test depths.

Other petrophysical logs provide important information directly related to formation permeability. Permeability is reduced by dispersed shale and anisotropy influenced by laminated shale, so logs providing information on clay content, such as geochemical logs, should be taken into account.

Both open fractures and matrix permeability strongly affect the Stoneley wave measured by the DSI Dipole Shear Sonic Imager tool. Stoneley waves, traveling along the borehole surface, reflect from open fractures. Fracture aperture is measured using either the magnitude of the Stoneley reflection coefficient or the current density from a borehole imager. Stoneley wave slowness provides a continuous scalar measurement of permeability at the borehole wall, which may be calibrated using multiprobe formation tester permeability measurements.



☐***Flow regime identification using the G-function. A plot of log G-function versus log delta time allows identification of spherical flow—a slope of –1.5—and radial flow—a slope of –1.0.***



☐***Verification plots. On plots of delta pressure versus delta time*** (top) ***and vertical probe pressure versus horizontal probe pressure*** (bottom), ***the modeled response is plotted with the acquired data. The match in both cases indicates the correct choice of model and the validity of interpretation results.***

relationship—the G-function—may be calculated by using both pressure transients. A plot of G-function versus delta time will approach a slope of –1.5 for spherical flow and –1.0 for radial flow. This approach was used to analyze the AGIP job (*left*).[13]

Once the flow regimes are identified, specialized plots may be generated for the periods of spherical flow and radial flow. Spherical analysis allows first estimates to be made for horizontal and vertical mobilities and the porosity-compressibility product. Radial analysis gives the horizontal mobility-thickness product.[14]

The initial estimates are used in formation response models coupled to a parameter estimator to arrive at the best estimate of formation parameters and achieve the best match between observed and calculated pressures. The final match is presented as verification plots—pressure versus time and lobe plots (*left*). For a lobe plot, the change in pressure at the vertical monitor probe is plotted against the change in pressure at the horizontal monitor probe during both drawdown and buildup.[15]

The separation between vertical monitor probe and sink probe—2 ft [60 cm]—did not allow AGIP to test across all zones of reduced porosity that were indicated from petrophysical interpretation of the openhole wireline logs. Several vertical interference tests were conducted over the reservoir to evaluate vertical permeability statistically. Although some dry tests were encountered, no permeability barriers were found. Results from the 1-gallon sample chamber test were in good agreement with the flow control test, and were also in good agreement with permeabilities measured by a drillstem test (DST) over this interval.

The anisotropy ratio for one reservoir from core plug data was 0.8 compared to 0.62 using the MDT tool measurements. The MDT tool results were considered to be more representative and have been incorporated by AGIP into their three-dimensional simulation model.

Two-Probe Test in Abu Dhabi

TOTAL used the MDT tool in four wells to measure permeability anisotropy in a Middle East carbonate reservoir prior to a pro-

13. Goode PA, Pop JJ and Murphy WF: "Multiple-Probe Formation Testing and Vertical Reservoir Continuity," paper SPE 22738, presented at the 66th SPE Annual Technical Conference and Exhibition, Dallas, Texas, USA, October 6-9, 1991.
14. For a thorough review of pressure test analysis: Ehlig-Economides et al, reference 1.
    Addis T, Last N, Boulter D, Roca-Ramisa L and Plumb R: "The Quest for Borehole Stability in the Cusiana Field, Colombia," *Oilfield Review* 5, no. 2/3 (April/July 1993): 33-44.
    Mobility is permeability divided by viscosity.
15. Zimmerman et al, reference 7.
16. Ayan C, Stofferis M and Mahmoud Y: "In-Situ Reservoir Permeability and Anisotropy Determination with a Modular Wireline Formation Tester," paper ADSPE 96, presented at the 6th Abu Dhabi-SPE International Petroleum Exhibition and Conference, Abu Dhabi, UAE, October 16-19, 1994.
17. Petricola M and Frignet M: "A Synergetic Approach to Fracture and Permeability Evaluation from Logs," paper SPE 24529, presented at the 5th Abu Dhabi-SPE Petroleum Conference, Abu Dhabi, UAE, May 18-20, 1992.

posed gas injection project.[16] The tests were carried out mostly between limestone and dolomite layers where permeability barriers were expected at the lithology change.

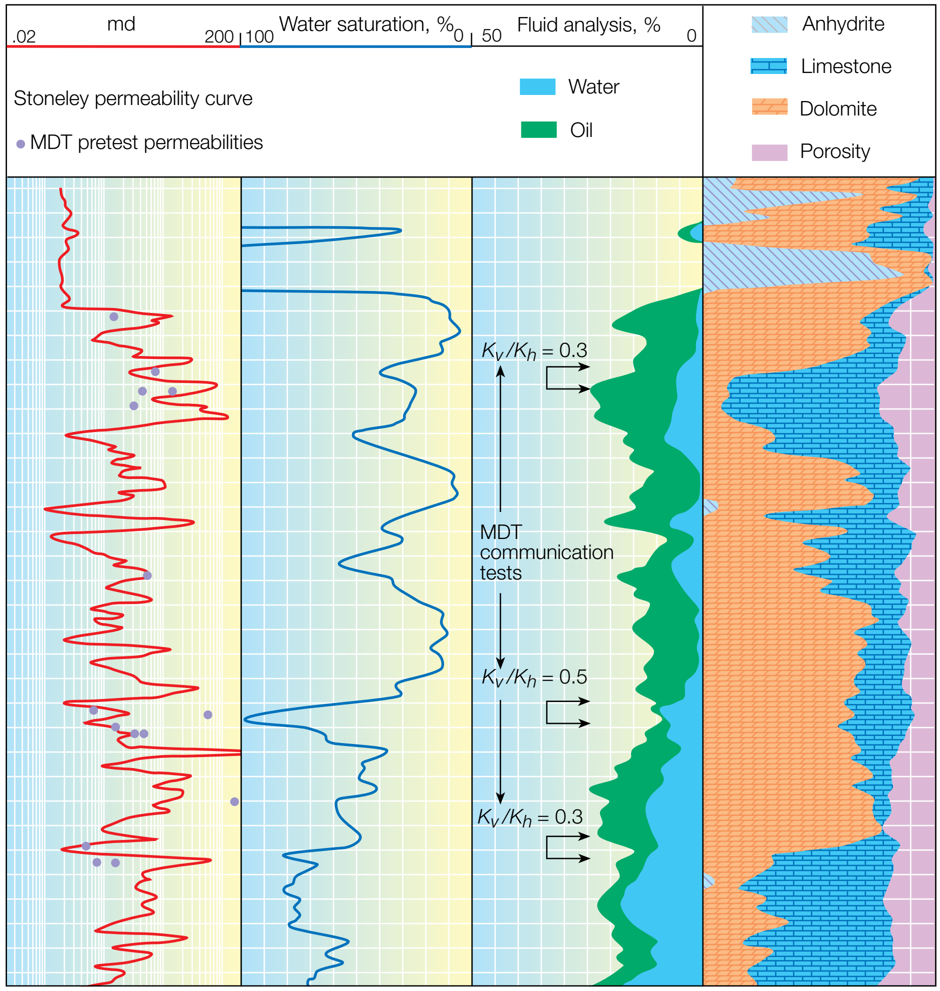
The MDT tool configuration with two single-probe modules was used to increase the spacing between the probes to 8 ft, so that each test would cover as much formation as possible (*page 27*). The flow rate source was the pumpout module, which can pump mud filtrate or formation fluids from the reservoir into the borehole.

The results from the drawdown permeabilities compare well to the Stoneley permeability log recorded by the DSI Dipole Shear Sonic Imager tool and show extreme permeability heterogeneity (*right*).[17] However, results from the vertical interference test measurements show significant differences when compared to permeability measurements from cores. The vertical interference test analysis indicates much lower horizontal permeability at the depth at which core data are available (*bottom, right*). High core horizontal permeability measurements are most likely caused by vugs and induced fractures and the fact that the measurements took place without overburden pressure.

Although core measurements showed vertical permeability to be almost as good as horizontal permeability, scaling up the data did not provide TOTAL with the correct value of anisotropy for their reservoir model—they had to use a much smaller value to match reservoir performance. The MDT tool test results showed reasons for this. Several MDT tests indicated the presence of permeability barriers; other MDT tests indicated that previously suspected barriers were not present. This enabled TOTAL to revise their simulation model for the gas injection program.

A Barrier Removed?

The importance of permeability anisotropy to sound reservoir management is not in dispute. Vertical interference testing with the MDT tool provides measurements of horizontal and vertical permeability early enough to attack problems of well completion design, stimulation planning and horizontal well trajectory. The resolution of the measurement fills the gap between that of well tests and that of core data so that reservoir models may be refined, leading to better field development strategies, such as enhanced oil recovery programs and infill well placement. —AM



***Comparison of MDT tool permeabilities to Stoneley permeability curve. MDT tool mobilities compare well with the Stoneley permeability curve** (left-hand track)**, both showing extreme heterogeneity. Also shown are the positions of three MDT tool vertical interference tests alongside the openhole log volumetric interpretation** (right-hand track).*

Core	Depth	Permeability		Description
	(m)	k_h (md)	k_v (md)	
1 (25 cm)	2947.25-2947.50	2283	84	Limestone, vug, induced fractures along stylolite 2
2 (19 cm)	2947.62-2947.81	111	30	Limestone, vug, oblique induced fracture
3 (19 cm)	2947.81-2948.00	663	24	Limestone, vug, towards bottom

Whole core results. The table shows the variation in permeabilities on measurements made under atmospheric conditions on three cores. The MDT tool vertical interference test conducted across the same interval gave a vertical permeability of 8.2 md and a horizontal permeability of 16.3 md. The significantly higher core permeabilities may be accounted for by scale of measurement differences and by the in-situ MDT tool measurement. The MDT tool measurement covered 8 ft of borehole compared with the 7.5-in. [19-cm] cores—the cores may not have been representative of that interval. The vugs and induced fractures contained in the cores would close under borehole pressures reducing the permeability.