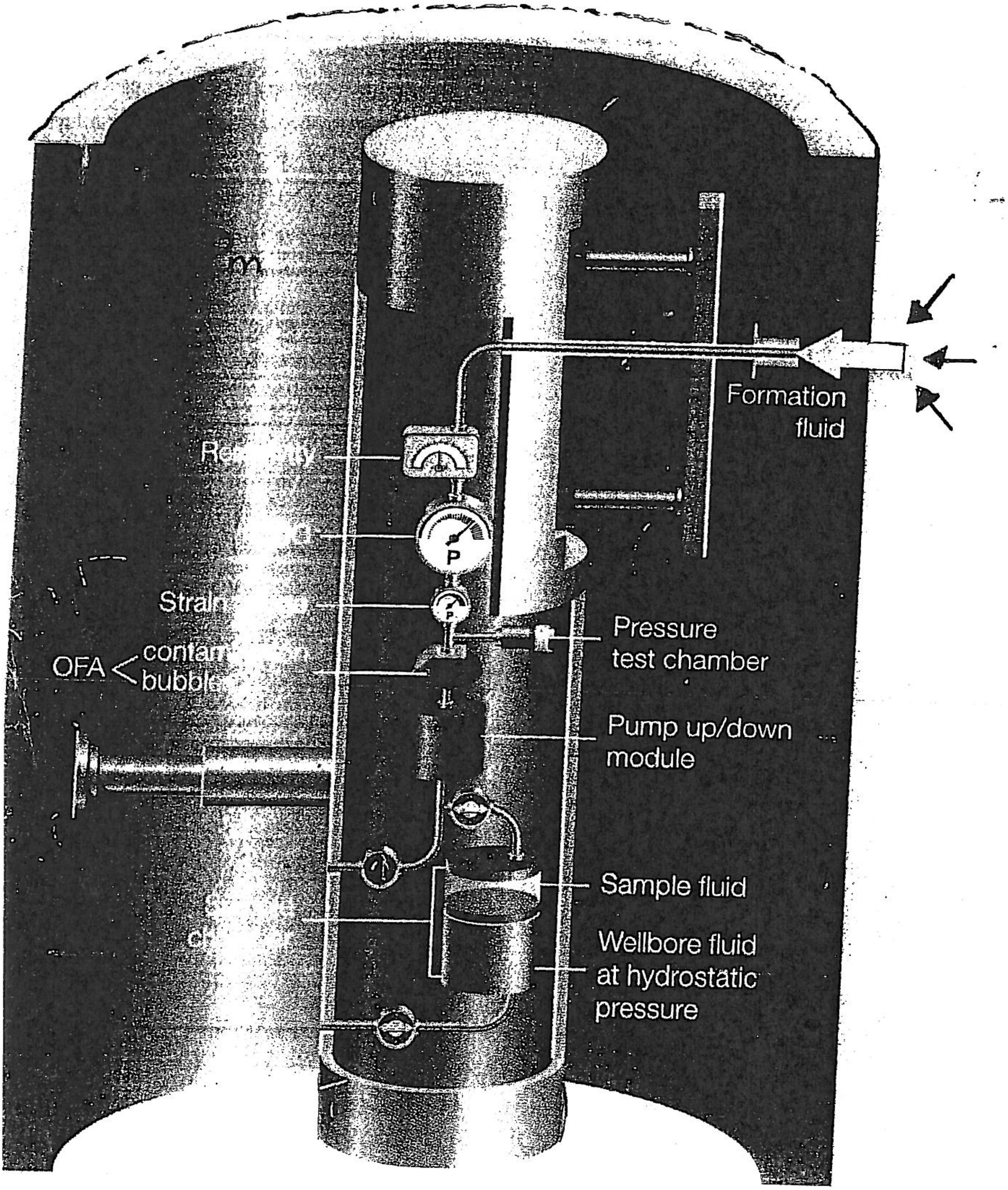
KABELTESTING

MDT



pen valve

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Why Wireline Testing?

Proper reservoir management requires formation pressure measurements in a wide range of conditions. Collecting representative formation fluid samples and determining permeability and permeability anisotropy are equally important. A new generation of wireline formation testers provides oil and gas operators with all this important reservoir information.

Formation pressure measurements taken within a well can be plotted versus true vertical depth to produce a pressure profile. The resulting pressure profile is extremely valuable in analyzing virgin and developed reservoirs. In virgin reservoirs, pressure profiles can be combined with geology, cores, seismic and conventional logs to develop a static model of the reservoir. Pressure profiles in development wells can offer an understanding of fluid movement within the reservoir. These profiles, combined with the production history, measurements from well testing, saturation monitoring surveys and the static reservoir model, are used to model the dynamic reservoir response—crucial for optimizing recovery.

In virgin reservoirs, vertical pressure profiles are obtained to

- determine fluid contact level
- determine formation fluid density in situ
- characterize reservoir heterogeneities
- determine completion strategy
- optimize the mud density for infill drilling.

In developed reservoirs, wireline testers are used to

- characterize vertical and horizontal barriers
- assess vertical permeability
- detect potential thief zones
- determine hydraulic communication between wells
- detect fluid contact movement.

Wireline formation testers are also used to collect formation fluid samples. In particular, the MDT tool attempts to improve the quality of samples by using techniques for downhole fluid analysis—a system to discard contaminated fluids before taking samples and to limit the drawdown pressure by using precision flow control methods.

Tests from wireline testers provide mobility profiles that help to pinpoint zones of better productivity. The recorded transient pressure response at each station can be analyzed to estimate permeability. In homogeneous formations, the multiprobe tester can estimate horizontal and vertical mobilities; in laminated formations, this tool enables the study of potential permeability barriers and their effect on vertical fluid movement.

Wireline formation testing data are essential for analyzing and improving reservoir performance and making reliable predictions. These, in turn, are vital to optimizing reservoir development and management.

Wireline tester technology is steadily progressing. Continued efforts in the development of new modules, constant evolution of interpretation methods, improvements in downhole sensors and better control of the downhole environment have all increased the capabilities of wireline testers significantly.

Pressure profiles

Formation pressure is obtained by withdrawing a small amount of fluid from the formation to generate a short transient test (Fig. 2-1). The pressure response is then recorded during shut-in until it stabilizes. An unlimited number of pressure transient tests, or “pretests,” can be performed at different depths during a single run of a wireline formation tester to produce a pressure profile.

In thick reservoirs with relatively high permeabilities—tens or hundreds of millidarcies or higher—vertical pressure profiles are used to determine in-situ fluid densities and fluid contact levels, as shown in Fig. 2-2. This type of pressure measurement requires gauges with high accuracy and resolution. Standard quartz gauges, although suitable for fluid gradient determination, require long stabilization times when subjected to sudden changes in temperature or pressure, a common occurrence during formation tests. Strain gauges have a better dynamic response but do not offer the accuracy or resolution needed for most fluid gradient determinations. A new gauge was needed that could combine the accuracy and resolution of the quartz gauge with the dynamic response of the strain gauge. These requirements were met in the Schlumberger CQG* Crystal Quartz Gauge.

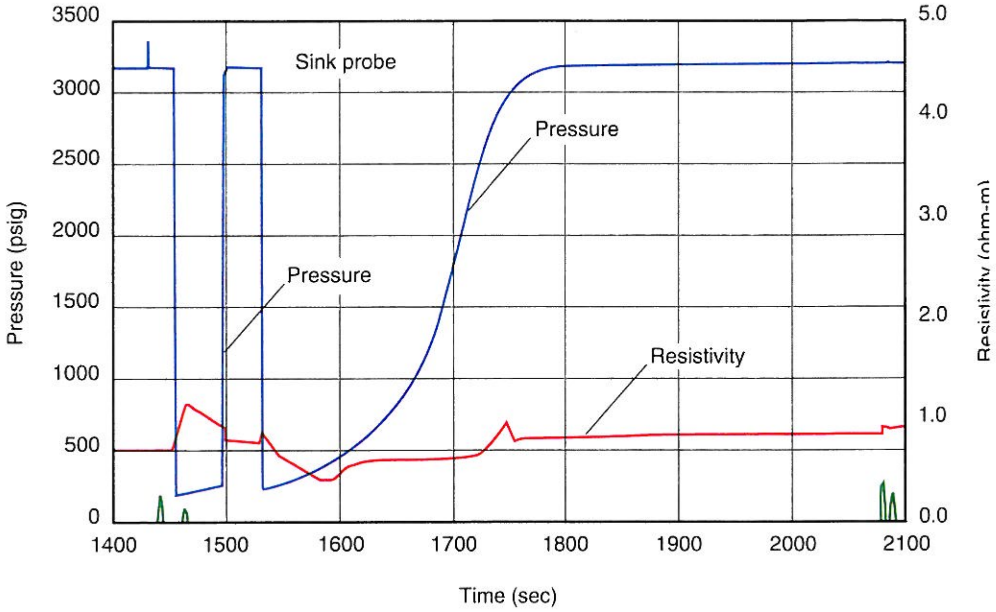

Figure 2-1. *Typical pretest followed by sampling (Zimmerman et al., 1990).*

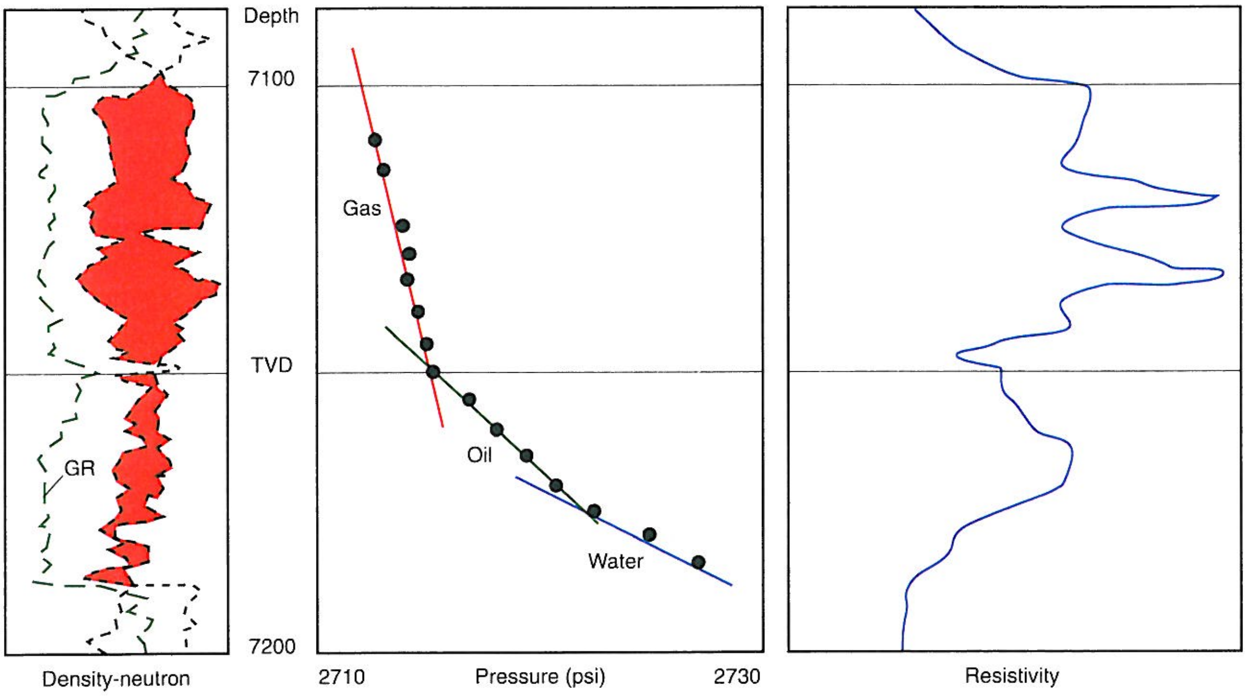

Figure 2-2. *Vertical pressure profiles can be used to define fluid type within the reservoir and locate fluid contacts.*

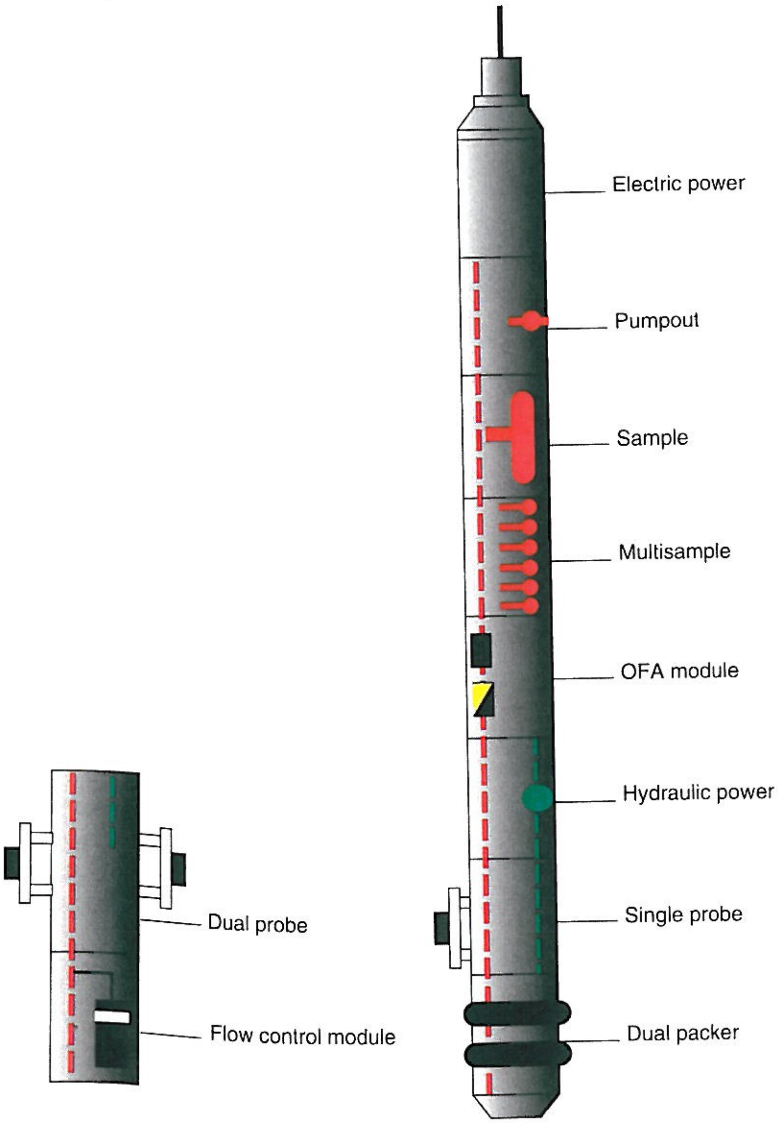

Figure 4-1. *MDT tool with all modules.*

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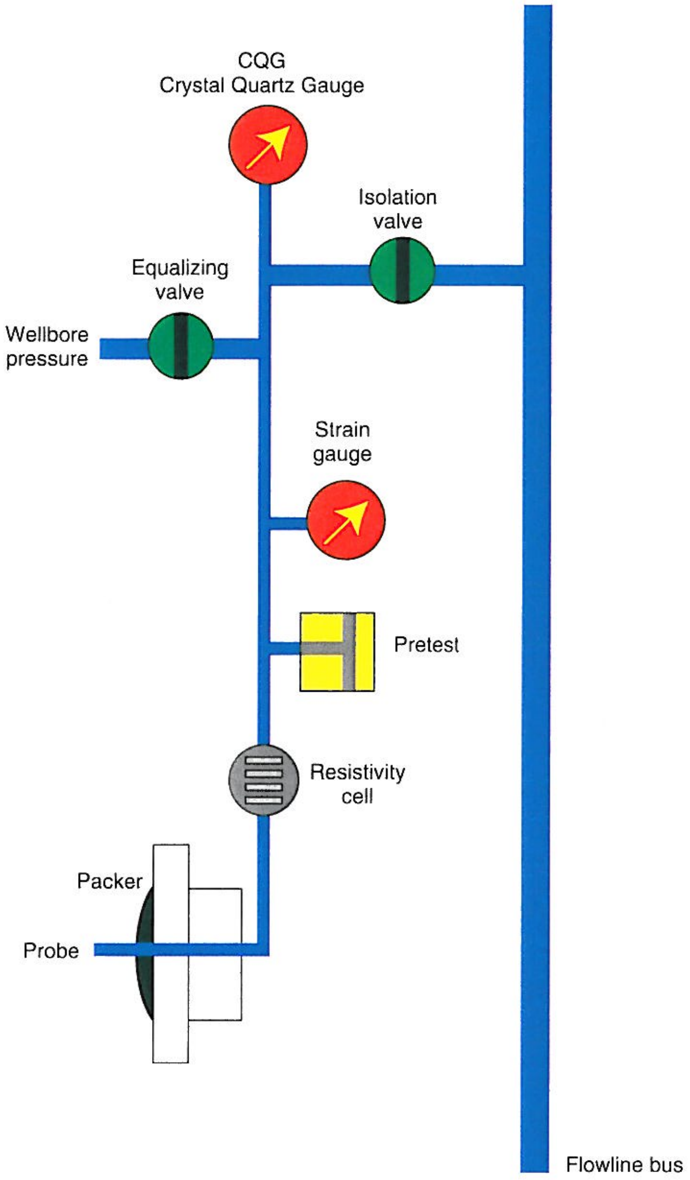


Figure 4-3. Single-probe module.

Dual packer module

The dual packer module, schematically shown in Fig. 4-24, provides two inflatable packer elements to isolate a borehole interval for testing and/or sampling. The pumpout module uses borehole fluid to inflate the packer elements to about 1000 psi above hydrostatic pressure. Spacing between the packer elements varies with hole size, but the minimum distance is about 3 ft [92 cm]. The entire borehole wall is open to the formation, so the fluid flow area is several thousand times larger than with conventional probes. The dual packer module can be used as an alternative to conventional probes.

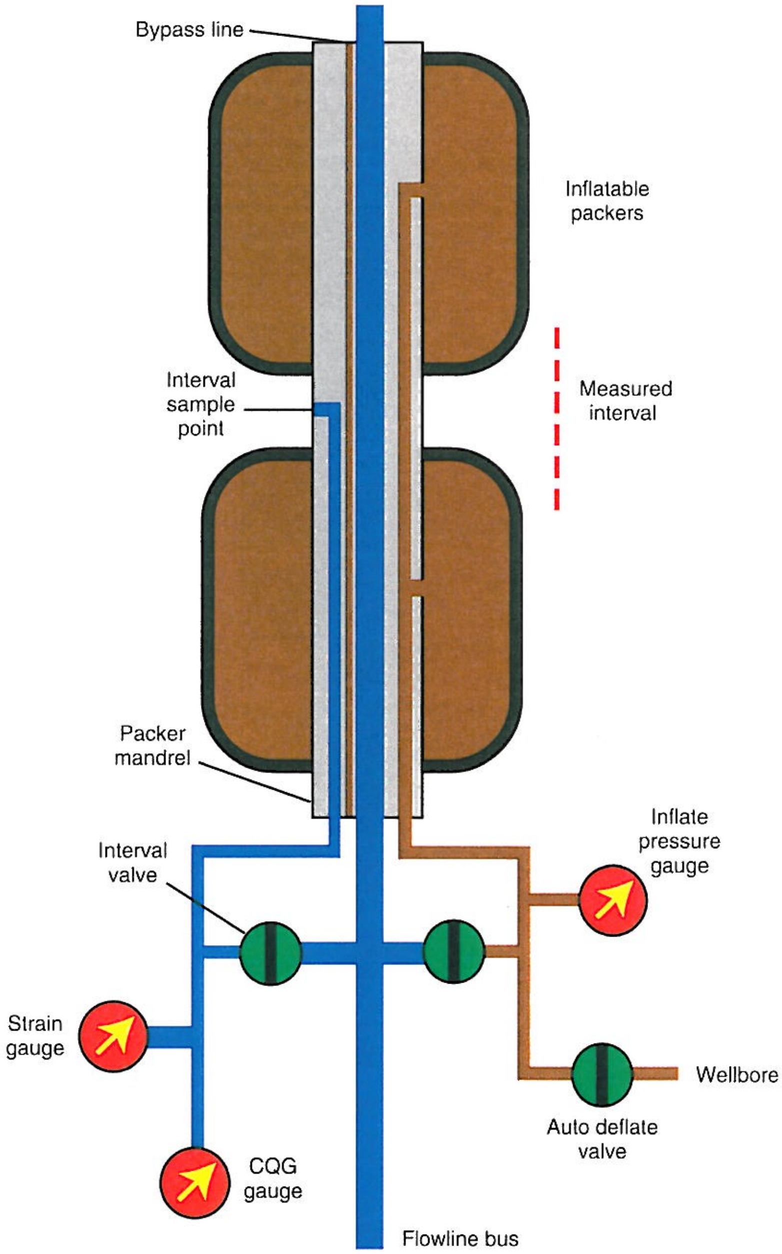
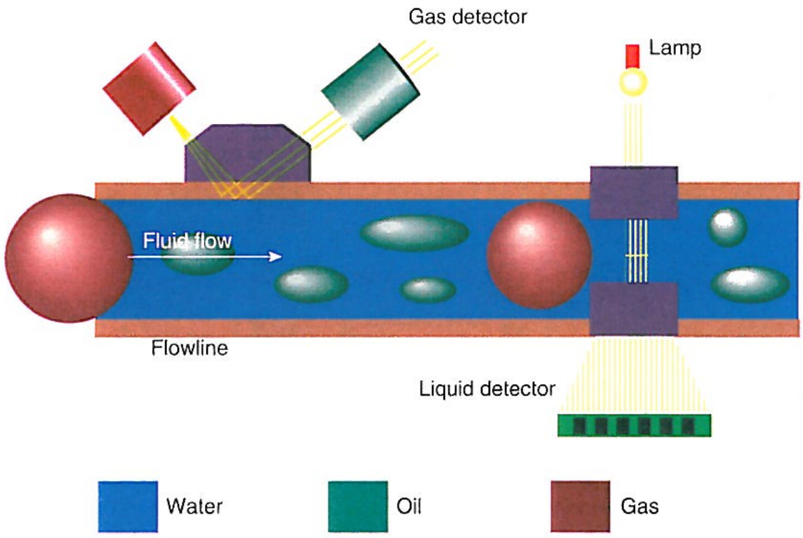


Figure 4-24. *Dual packer module used to isolate an interval for testing and/or sampling.*

Figure 4-35. The OFA module with its two sensor systems: one for liquid detection and analysis and the other for gas detection.



Multisample module

The third requirement for PVT-quality samples is an appropriate sample receiver. This requirement can be satisfied with either conventional sample chambers or the multisample module. The multisample module contains six sample chambers mounted in a single carrier (Fig. 4-36). Each sample cylinder collects a 450-cm^3 sample suitable for full PVT analysis. Surface-controlled valves open and close specific sample bottles as required. This makes it possible to take multiple samples during one tool set at various times of fluid flow or to fill single sample bottles at various well depths. A throttling valve, acting as an inlet choke, provides pressure control while sampling. Additional control devices, such as a water cushion, can be used in each of the six sample cylinders. This is especially useful for controlling sampling rate.

Figure 4-37 is a schematic representation of the multisample module. There are two banks of three bottles each. Two throttle valves allow the probe to be placed either above or below the module. If the probe is above the module, the top throttle/seal valve is used to control flow into any one of the bottles, and the bottom throttle/seal valve is sealed. If the probe is below the module, the bottom throttle/seal valve controls the inflow and the other valve is sealed.

Each bottle can be charged with a water cushion below the sample piston. The check valve at the bottom of each bottle ensures that the water leaving an adjacent bottle does not enter any other bottle. There is one set of flow restrictors for each bank of three bottles. Once a bottle is filled, the normally open valve is activated (closed) to seal the bottle.

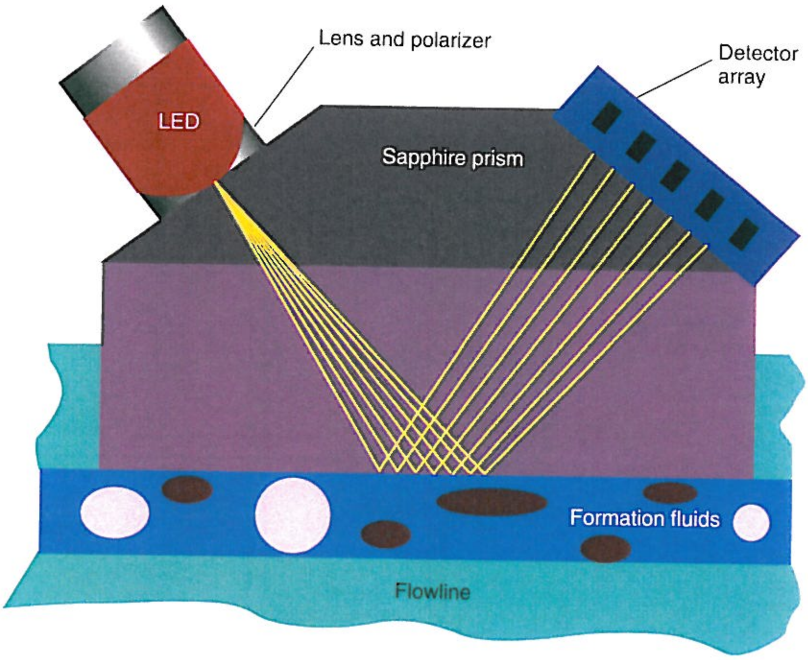


Figure 10-8. Basic gas detector design.

At present, water holdup is calculated directly from the calibrated responses of the detectors tuned to the two water peaks relative to those tuned to wavelengths at which water has very little absorbance. Subtraction from unity then gives hydrocarbon holdup. In addition, the log presents an oil indicator by shading the separation between the output of the detector tuned to the oil peak and the output of the detector tuned to a wavelength between the oil peak and the 1450-nm water peak. The magnitude of the separation gives an approximate measurement of the oil volume fraction in a gas-oil mixture. When combined with the hydrocarbon holdup estimate, this can yield a rough appraisal of oil holdup. Since scattering reduces light transmission, a shift from the baseline of the optical density curves shows the magnitude of scattering. Independently, the gas detector flag indicates the presence of gas. The recording also presents optical densities measured by each transmission detector. These are tracked in time and give additional indications of changes in flowline fluid composition.

Further developments in OFA measurement and interpretation are in progress, and new applications can be envisioned, such as aiding interpretation of drawdown pressure tests, providing new information on formation invasion and making quantitative estimates of bubblepoint under downhole conditions.

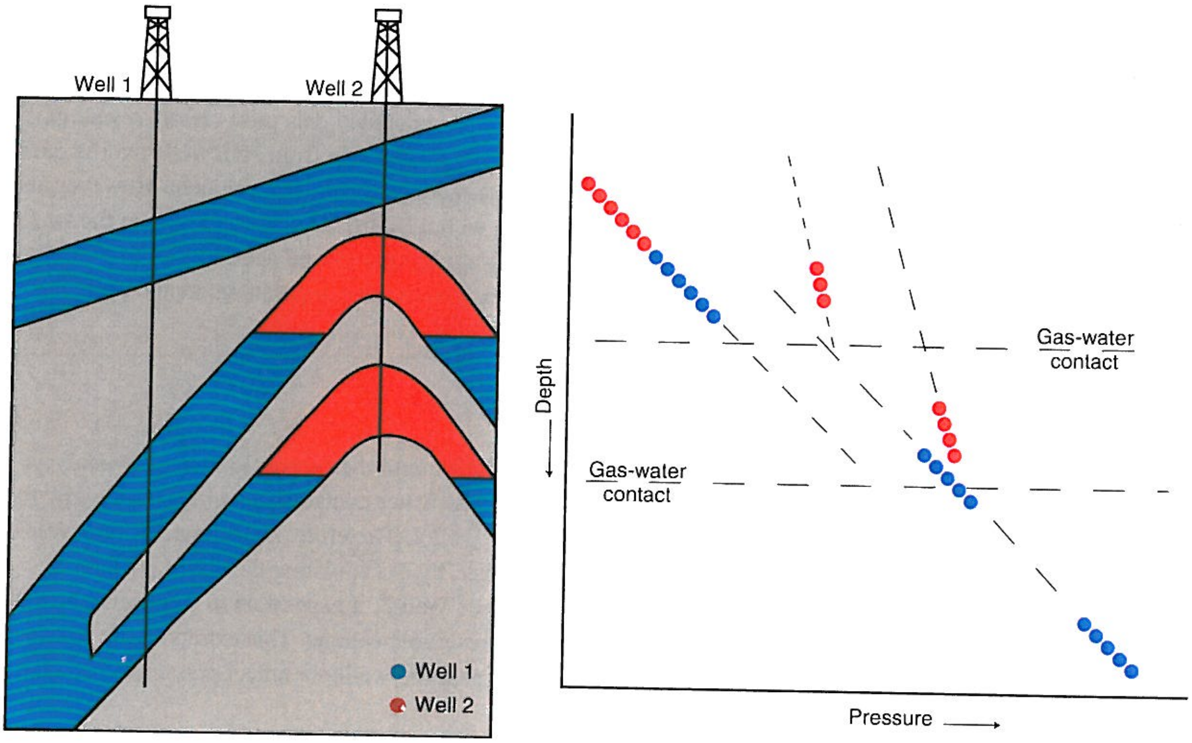
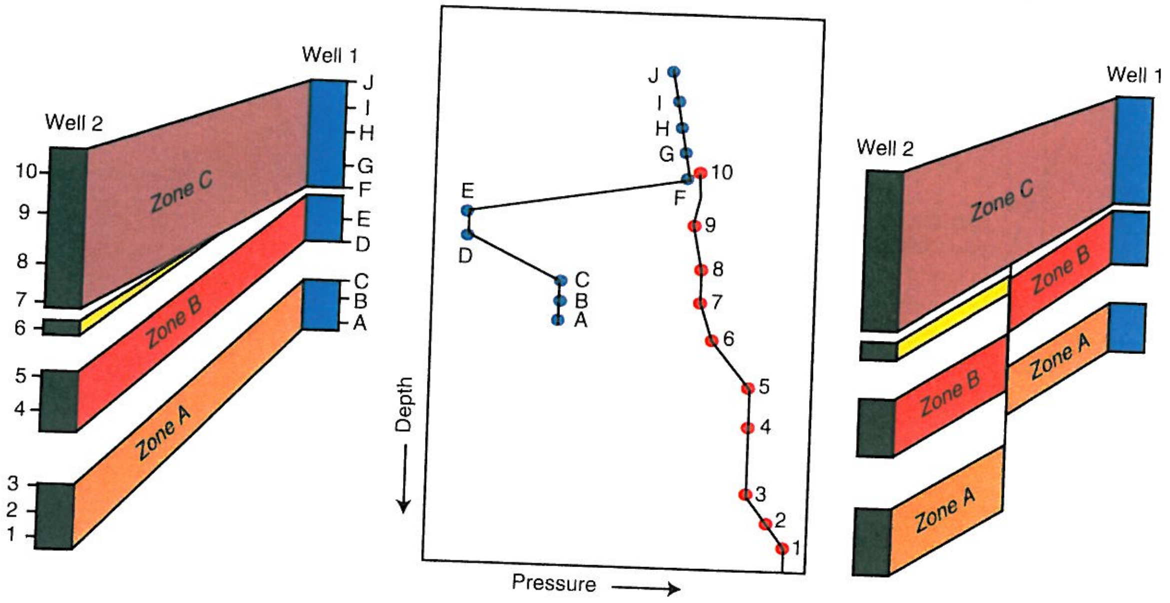


Figure 8-6. Determining the gas-water contact by extrapolating the water gradient of Well 1 and gas gradients of Well 2.

Barrier detection

Flow barriers have prevented formation fluids from reaching equilibrium over geologic time. Because the fluid has not reached equilibrium, a potential difference exists on opposite sides of the barrier. This pressure potential means that formation fluid would flow if the barrier were removed. Variation in potential can easily be seen when carefully analyzing gradients and provides a means of identifying flow barriers.

Gradients may not be continuous through what is thought to be a single reservoir. In these instances, two or more similar or identical gradients can be identified; however, they can have a potential difference because of an existing flow barrier (Fig. 8-7 left). Vertical flow barriers can be identified by this potential. In this example, the gradients are nearly the same but potential can be seen between the two gradients. The flow barrier prevents fluid mobility, and pressure stabilization has not occurred, resulting in two separate reservoirs. Similar situations occur when two different gradients with different potentials fail to intersect. This condition is shown in Fig. 8-7 right.



Log data

Log and RFT data

Figure 8-8. Complex structures.

Developed reservoirs

The static reservoir model is usually the basis upon which the reservoir is initially produced. Projections, based on this reservoir model, provide expected production data and estimate when reservoir pressure maintenance or other improved recovery techniques are required. The static reservoir description must be modified as reservoir characteristics appear during production. Reservoir pressure measurements from conventional well tests are a primary method used to determine the reservoir's response to production. However, wireline pressure measurements have proved extremely valuable in providing detailed information on the internal characteristics of developed reservoirs.

In development wells, the observed formation pressures may already be affected by either partial depletion or pressure maintenance. Therefore, the new development well can be used as an observation location at which the current state of the reservoir can be measured on a vertically distributed basis. The measured pressure profile reflects the response of the reservoir to production/injection, and it is evident that the pressure information may not be interpreted in terms of reservoir structure and fluid distribution without knowledge of previous production. Reservoir simulation may be the only possible approach to interpret wireline pressure data on a fieldwide basis. The following pages include some examples of the use of pressure profiles in developed reservoirs.