Down and out in logging
Two years ago, horizontal well drilling was rare in the Middle East. Today, the number of new horizontal wells is growing rapidly and their locations are becoming more diverse in the region.

In this article, Joe Johnston draws on the experience gained in logging a variety of formations and conditions in the Middle East to highlight some of the major pitfalls in horizontal well log interpretation.

Joe also considers the complex problem of how to evaluate open and cased holes.

Contributors: Steve Bruce of Dowell Schlumberger, Dubai, UAE and Bill Newberry of Schlumberger Data Services, Dallas, USA.
Before drilling a horizontal well it is critical that the correct logging tools are selected by the petroleum engineer. This can only be ensured by first creating an accurate model of expected formations based on nearby vertical wells. The choice of well also depends on the purpose of horizontal drilling (figure 3.1).

Across the Middle East, attaining each objective has met its own problems. If fractures are being hunted, how can they be identified? If gas or water is the problem, can the distance from the contact zone be evaluated? When the well is brought into production, can its performance be monitored?

Open hole evaluation

In a vertical well, the logging objectives of an open hole are generally:
- Determining the oil-water and gas-oil contact.
- Determining lithology and porosity.
- Evaluating saturation.
- Identifying barriers in the reservoir.
- Determining pressure and permeability profiles.

When the well goes horizontal these no longer apply for several reasons:
- Oil-water and gas-oil contacts are being avoided because the well’s objective is confined to the oil zone.
- Saturation is assumed to be constant from the start of the well project (though there can be surprises).
- Lithology is supposedly well known from local vertical wells although the information can be misleading (figure 3.2).

Logs in a horizontal environment are used for:
- Identifying fractures, either to assist production or where fractures could cause problems by connecting to the water table.
- Evaluating saturation, lithology and porosity.
- Establishing the proximity to layers such as tight zones or cap rocks, ie geometry.
- Determining pressure and permeability profiles.
- Identifying heterogeneities.

Fig. 3.1: Some possible horizontal objectives: • Crossing as many fracture zones as possible to increase production • Staying as far away from the water table as possible to minimize water production • Staying as far away as possible from the gas cap to minimize gas production • Penetrating a tight reservoir zone to recover bypassed oil • Producing only the narrow oil rim of a gas reservoir to extract the oil before gas production starts.

Fig. 3.2: The vertical well misses the tight zones and the logs will hardly react to the thin shale bed. However, the horizontal well encounters tight zones and some of the logs will respond to the shale bed.
Cased hole evaluation

In a cased hole, the interpreter has two main objectives when logging a vertical well. The first is saturation monitoring for water breakthrough and coning. The second is to obtain production profiles to identify producing zones and their contribution to the total. This information also shows fluid distribution and entry.

In horizontal wells these objectives also hold true. However, the interpreter faces a number of new problems. The first is specifically related to the well’s horizontal orientation. Multi-phase flow is common across the Middle East and, in the horizontal environment, this results in fluid segregation, with the heavier fluid moving along the low side.

All the fluids are moving at different velocities and thus the spinner, normally lying on this side of the hole, only reads the slower moving heavy fluid. Even if the spinner is centred, it will read an intermediate velocity (figure 3.3). The story is further complicated by vertical variations along the well’s length (figure 3.4). The fluid flow becomes a series of eddies, complex patterns and segregated fluids, leaving the spinners completely confused - especially at low flow rates.

Fig. 3.3: LYING LOW: When drilling a horizontal well, the fluids may be multi-phased. The heavier, slow moving portions tend to be on the lower side of the hole. Reading a true fluid velocity becomes complicated as the spinners, at best, only read an intermediate velocity, or the velocity of only one phase.

Fig. 3.4: THE UPS AND DOWNS OF DRILLING: Horizontal wells are never exactly horizontal. Depth variations along the length of the well encourage pockets of segregated fluids to develop. In addition, the flow patterns become a series of complex eddies.
In addition, the petroleum engineer needs to consider the three main completion designs - barefoot, slotted liner and cemented liner (figure 3.5).

Barefoot completions are the simplest of the three although they are limited to where formations are strong enough to support them. They can be used as an initial production completion which is then converted to a slotted or cemented liner. Production logs from a barefoot completion produce good results as the oil flow is contained within the wellbore. However, tool access along the ramp section can be impeded by rough walls. Caves lead to complex flow patterns which require more detailed interpretation.

Cemented liner completions offer the easiest access for tools and production logging runs are readily interpreted. However, a slotted liner causes the greatest difficulties. Complexities arise because the flow is partly outside the liner and the tools only read internal flow. Additional problems are created if the open hole is irregular, since this forces the flow to enter and leave the casing, giving erroneous readings on the spinners.
**Tool responses**

Logging tools are thus introduced into a complex and unfamiliar environment.

The tools were designed to measure properties of formations crossed by vertical wellbores. To characterize the responses, designers used a layer-cake model with each layer thick enough to be read accurately by the tool. Formations were considered infinite and homogeneous to simplify the model. In practice, variations from the ideal model have been studied and are well understood. For example, terms such as shoulder bed were added to the models for resistivity tools, and charts (figure 3.6) are available to make any necessary corrections.

In horizontal wells, everything seen by the tool is at odds with the design. There is no homogeneity in any direction. Layers are seen going away from the tool instead of being crossed in a continuous progression. Depending on their measurement systems, individual tools give a variety of responses to the horizontal well (figure 3.7). And, these differing responses have to be understood to achieve the interpretation objectives.

The zone investigated by a logging tool is characterized by the tool’s geometrical factor (figure 3.8). Deep resistivity tools, as their name implies, read far into the formation’s virgin zones. Most tools only read the invaded zone, less than 12 in. In vertical wells, the invaded and virgin zones are invariably in the same rock. In a horizontal well, this simple assumption may not be valid. Shallow-reading tools could be looking at something completely different to the deep-reading resistivity tools leading to interpretation difficulties.

It is difficult to design a tool specifically for horizontal wells since there is no way of uniquely characterizing all horizontal wells. However, a significant amount of development has been undertaken and some new devices are expected in the near future.
A model approach

One of the most important aspects of interpreting horizontal wells is the early preparation of a logging programme. This requires a clear understanding of the well’s objectives and target zone. Knowing details of local formations, from nearby vertical wells, allows the interpreter to use the most powerful tool available - modelling.

Modelling of log responses has progressed rapidly in recent years and in the horizontal environment is invaluable in explaining and interpreting log responses. Models come in various forms. Resistivity tools, especially induction, have rigorous programs which can predict the tool’s response to a large number of possible situations. One such program is ELMOD (Middle East Well Evaluation Review, Number 8 1990).

Nuclear tools have their own, much simpler, modelling using geometrical factors to predict a tool’s volume of investigation. The analyst can also use another program, SNUPAR, to compute the log reading when the tool is surrounded by any composition of minerals and fluids. In fact, the program usually assists in interpreting complex lithologies.

For example, SNUPAR could predict the neutron density reading in a formation containing both methane and carbon dioxide gases, or the capture cross-section from a Dual-Burst* Thermal Decay Time tool in a slotted liner full of oil.

Using this sort of foreknowledge, the recorded logs from a horizontal well are evaluated with a higher degree of confidence. Hence, there are major advantages in using familiar, standard tools to evaluate each horizontal well individually.

Displaying horizontal well evaluation information in an easily comprehensible fashion is not straightforward. The Horizontal Well Advisor* program clarifies the picture by plotting logs on the well track. This enables the interpreter to take a quick look at the whole well. Figure 3.11 shows one such example through the Austin Chalk in Texas, USA. This formation produces through fractures and therefore the logs displayed concentrate on this area.

Fig. 3.10: KEEP ON TRACK. Following a planned well path can be achieved with great accuracy. This example from Canada shows the comparison between proposed and actual well paths. Modeled log responses were used to determine the actual path.

Open hole logging

Without gravity to pull a tool down the hole, logs in horizontal wells are obtained in one of two ways.

First, there are Tough Logging Conditions (TLC*) conveyed logs (Middle East Well Evaluation Review, Number 8). Here, the required tool string is attached to the bottom of the drill pipe which is then used to push the tool down the hole. A wet connect system allows electrical connection with the tools.

Any log can be run using this system but the operation takes longer than conventional logging. For this reason, several tools are joined together to form ‘super-combos’ to maximize the information obtained from a single trip. This ability to mix any combination of logging tools has led to TLC being the most popular method of logging in the Middle East.
The second method is Logging While Drilling (LWD). The curves obtained - resistivity, natural gamma ray, neutron porosity and bulk density - can be relayed to the surface in real-time or recorded downhole and replayed at surface when the drillstring is retrieved. This has a number of advantages over TLC primarily because the information is recorded early in the drilling process and the formation is seen in its virgin state. A repeat pass made while pulling out gives a time-lapse resistivity measurement. Permeable zones are invaded by mud, resulting in a changed reading on the return pass. An estimate of relative permeability can be based on this change.

In real-time mode, LWD can also give advance warning of problems such as the hole approaching gas, water or cap rocks.

**Running-in resistivity**

Resistivity logs are usually the first logs run in a well, with the aim of computing water saturation. In horizontal wells, this should be constant, but this is not always the case (figure 3.12). In addition, in a horizontal well, these deep reading devices are used to evaluate the proximity of boundaries. Resistivities from logs in vertical wells are used to set up the modelling program ELMOD. The tool’s response close to a possible nearby layer can then be predicted. Figure 3.14 shows a typical induction tool.

---

**TYPICAL TOOLS**

Logs used in standard open hole evaluation are:
- Resistivity either Laterolog or Induction tool.
- Porosity, from a neutron tool.
- Bulk Density and Photoelectric factor from the Litho-Density* tool.
- Sonic from a standard borehole compensated tool or with wave forms from an Array Sonic* tool or with dipole shear from the Dipole Shear Sonic Imager (DSI*) tool.
- Dipmeter, from either the standard dipmeter tool or the Formation MicroScanner* (FMS) for additional borehole images.
- Formation pressures from the Repeat Formation Tester (RFT*) tool.
- Gamma Ray from a Gamma Ray Tool - or Natural Gamma Ray Spectrometry (NGS*) tool.
- Dielectric constant from the Electromagnetic Propagation (EPT*) tool.

---

**Fig. 3.11 (Below):** The Formation MicroScanner image is accompanied by the wiggle trace and also a Quick Look interpretation of fracture occurrence, QFRAC, shown as spikes beside the image.
response to the approach of an overly-
ing shale bed. This is common in many parts of the Middle East where low resistivity shale cap rock overlies the reservoir, eg the Shuaiba reservoirs of northern Oman.

When evaluating the log response, it is critical to understand the zone under investigation. In the vertical case, the zone of investigation spreads away on either side of the tool into the same bed. When the well is horizontal, the tool sees the rock layers as a series of annuli. The resistivity of each individual layer is unknown and the combined effect can lead to false readings. In addition, the induction and laterolog tools react in different ways to this phenomena. The laterolog tool sees the formation as a set of series resistances whereas the induction tool sees the same set in parallel. Non-symmetrical layering causes further problems.

The modelling program is set up to account for layering anomalies - except non-symmetry. In the non-symmetrical case, a problem is indicated by the dramatic deviation of actual log responses from those computed. Further models are then defined to match the log and produce a best-fit formation model.

**Pinpointing porosity and lithology**

Density-neutron tools are used to evaluate porosity and lithology in both vertical and horizontal wells. In the latter case, the tools point towards the bottom of the hole to ensure good pad contact. Therefore, they only react to beds on the low side of the hole. This in itself can cause some complications. For example, if there is a thin shale bed, around 30cm thick, being cut by the wellbore over a distance of 10m, the tools only read this layer (figure 3.16). In a vertical well, through the same bed, the tools will probably miss this bed completely - unless they were logged at high sample rate because 30 cm is less than the tool’s vertical resolution. Therefore, the tools cannot distinguish between a lithology change, where the bed surrounds the borehole, a thin layer on the bottom of the hole only, or a thick zone starting on the low side of the hole.

Thus the interpreter can suddenly be faced with unknown lithologies in a well-known formation. However, by referring to the response of other tools it is possible to decide whether the shale seen by the nuclear tools is a true thick bed or merely a thin streak. If the shale is thick the resistivity tools react by showing a lower reading.
Fig. 3.16: THICK OR THIN? The tool response in the horizontal well is the same for three very different cases.
Conversely, a thin bed at the bottom of the well scarcely affects these tools since they read deep into the formation. FMS images show a complete picture around the borehole and can confirm whether the shales seen by the neutron-density tool are located beneath the wellbore or around it. These lithology (and possible porosity) changes provide important information on the extent of the beds affecting horizontal wells. Problems caused by heterogeneities in the reservoir can be predicted leading to improved completion planning.

The LWD neutron and density measurements, while employing the same principles as the wireline-conveyed equivalents, have one major difference. These tools are part of the drillstring and hence rotate, i.e., they measure the entire formation around the borehole. This means that they will react differently to layering. Comparisons with their wireline equivalents can thus provide additional information.

Gamma Ray (GR) tools are used, as in vertical wells, for correlation and computation of shale volume. GR peaks show where the well crosses a given bed. However, the humble GR has another, more important, use in this environment due to its measuring system. Like laterolog and induction tools, the GR is not azimuthally focussed. It reacts to the formation all around the borehole, rather than seeing ahead. Its depth of investigation is similar to the other nuclear devices. Thus, if a shale bed approaches the wellbore from above, the GR reacts before the neutron-density, which faces downwards. If it approaches from below, all three tools will react together. Hence, we start to picture the layer geometry around the well (figure 3.17).

Fig. 3.17: I SPY!: Understanding the volume of investigation for each tool is crucial. The GR sees equally in all directions and hence, when a shale bed approaches from above, it reacts before the neutron density tool, which only "sees" in one direction. Where a shale bed approaches from below, all three tools react together.
Sounding out thin beds

The Array Sonic tool is used widely in the Middle East and its successor, the DSI tool, is currently in use across Oman, Saudi and Egypt. Potentially, they offer the best solution to a number of a horizontal well puzzles. Both tools employ transmitters with an array of receivers at varying distances. The signal picked up by the receivers has passed through the formation layer near the borehole and, therefore, the slowness of this bed is computed. If this is merely a thin streak with the virgin formation surrounding it, the picture changes. In this case, the signal not only travels in the thin shale but also in the faster reservoir rock. The far receivers pick up this signal before the one travelling in shale, thus the true formation slowness is measured. In addition the layer has been positively identified as a thin bed (figure 3.20).

Fig. 3.18 (Above): The velocity of the sonic wave through the formation adjacent to the borehole is slower than that of the wave travelling through rocks further from the well. Thus, the direct wave in the adjacent formation only arrives first at the near receiver 1. The waves through the faster rocks arrive sooner at receivers 2 and 3.

Fig. 3.19 (Right): DSI tool showing the position of the two dipole transmitters and receiver arrays.

The DSI tool has two orthogonally positioned dipole transmitter-receiver pairs (figure 3.19). This allows the tool to look for anisotropy around the borehole. Analysing the signals from both transmitter-receiver pairs adds to the information about the bedding around the borehole.

Layering up to 40ft away from the borehole, with good formation contrasts, has also been identified by using the arrays of receivers in the same way as a seismic survey. An image of the formations can be obtained up to 40ft from the borehole.

Fig. 3.20: The example is taken in a relatively shale-free sand zone in a Middle East reservoir. The discrepancy in readings is due to the variation in sonic slownesses for each layer encountered by the signal. Those measured by the receivers close to the transmitter are reading a slower formation than those spaced further away. The difference is caused by the near receivers detecting the wave travelling through the damaged zone around the wellbore while the far receivers are reading the faster virgin formation.
The complete image

The conventional use of the FMS is to identify bedding and other features in vertical wells. So it appears an odd tool to use in horizontal wells. However, it has an advantage over other current tools. It measures all around the wellbore with known orientation. This means that the images it generates give a clear picture of a number of very important features:

- Fractures, one of the reasons for drilling horizontally.
- Anisotropy, the presence of the neutron-density confusing layers.
- Bedding planes cutting the well.
- Resistivities around the borehole.

Fractures are the most obvious feature of vertical well FMS images. They appear as high-angle events compared to the usually low-angle bedding. The horizontal environment reverses this picture. If the well is successfully drilled at right angles to the fracture plane, fractures show up as flat events on the image. High-angle events are the bedding planes intersected at 90° by the well. These bedding planes can be computed and mapped like any other beds.

Resistivity responses are easier to interpret using the borehole coverage obtained with a FMS tool image. A synthetic resistivity curve, generated for each pad, is compared with standard curves. The variations help to interpret readings from deep resistivity tools (figure 3.22).

Spotting pressures

The RFT tool is used in vertical wells to obtain pressure readings and fluid samples from the reservoirs. This also applies in horizontal wells, but here the reservoir engineer gains some additional benefits. A vertical well acts as a single point in a large field. It cuts through reservoirs showing contacts and vertical pressure distributions. The horizontal well traverses a large distance across a field thus pressure measurements describe how a complete section of a field is behaving. This has proved very successful in the Middle East in highlighting faults and blocks within the field. This information can lead to improved field completions and recovery (figure 3.23). These pressures are also important in reservoir simulations, providing another dimension to the models.

The individual tools described above must be used in combination to fully describe a horizontal well. Standard interpretation techniques can be applied to compute porosity, lithology and water saturation. More advanced techniques are necessary to obtain extra information on, for example, the bedding geometry. A horizontal well frequently encounters faults, pinch outs and the well path can drift in and out of the target bed. These heterogeneities have to be identified and, if possible, quantified in order to design an efficient completion.

Fig. 3.22: A four-pad device such as the FMS tool or the Stratigraphic High Resolution Dipmeter (SHDT*) tool can give resistivities at four azimuths around the borehole. The standard tools ‘average’ this information. Hence, the azimuthal readings give information on heterogeneities crossed by the well. The zone at 4,185m demonstrates this - two pads read the same as the standard tool, while another is high and the fourth low.
**Methods in cased hole**

Let’s consider a well that has been drilled, completed and put on production. Some time during its life, as with any well, cased hole operations have to be run. These could be part of a monitoring programme to evaluate saturation changes or to look at the production profile. As already noted, the completion type plays a large part in evaluating cased hole logs. Possibly the completion itself needs cased hole services.

Barefoot and slotted liner completions need no further work in order to produce. However, a cemented liner requires perforation. There are two ways of doing this. First, it can be achieved by running a through-tubing gun such as an Enerjet* or Scallop perforator. This has the disadvantage that only one side of the hole will be perforated (usually the low side) and only a short interval (10m - 15m) can be shot on each run in the hole. Therefore, a typical 400m section would require a lot of runs. The advantage of through-tubing guns is that the well is perforated under drawdown and production continues when the operation is completed.

The second method is tubing conveyed perforation (TCP) the advantages are:

- Any interval can be perforated in a single run, including as many blank zones as necessary.
- A pressure firing system can be used, hence no wireline in the well.
- Perforations are made all around the borehole, typically at 60° intervals.
- The well is perforated under drawdown.

One disadvantage is that the well has to be killed to pull out the guns after the operation. They cannot be ‘dropped off’ as in some vertical wells.

The other problem with cased hole logging is how to push the tools (and the through-tubing perforating guns) to the bottom of the well. TLC equipment with its drill pipe is obviously unsuitable since the drill pipe cannot pass through the tubing. The answer is to thread a logging cable through a length of standard coiled tubing. The slim logging tools used in cased hole evaluations can then be directly attached to the end. Cased hole environments also differ from open hole in that pressure control is necessary as the wells are ‘live’.

---

Fig. 3.21 (Left): The top of this section starts with an open fracture crossing the well around 1,347.6m. The black (low resistivity) feature is at a low angle, meaning the well is intersecting a fracture almost at right angles. Another fracture is visible a couple of metres lower. Between these two, the pads exhibit a classical FMS tool response in the horizontal environment. Three pads read high values while the fourth reads much lower – indicating a heterogeneity. In many horizontal wells this is the most common response. Continuing further along the well, other examples are found. Beyond the second fracture at 1,349.5m, two pads read low while the other pair read high. Then the situation changes with one reading high while the others are low.

Fig. 3.22 (Left): The top of this section starts with an open fracture crossing the well around 1,347.6m. The black (low resistivity) feature is at a low angle, meaning the well is intersecting a fracture almost at right angles. Another fracture is visible a couple of metres lower. Between these two, the pads exhibit a classical FMS tool response in the horizontal environment. Three pads read high values while the fourth reads much lower - indicating a heterogeneity. In many horizontal wells this is the most common response. Continuing further along the well, other examples are found. Beyond the second fracture at 1,349.5m, two pads read low while the other pair read high. Then the situation changes with one reading high while the others are low.

Fig. 3.23 (Right and below right): The RFT tool can be used in horizontal wells to map the pressure profile across large areas of a field. This can highlight any faults and blocks in the field, aiding reservoir management.

Fig. 3.24 (Bottom right): Using modelling techniques for resistivity tools, a synthetic log can be obtained to compare with the actual log. If the data does not agree, the model is changed until a reasonable match is found. The response functions of the GR and neutron-density are used to fine tune the results when the boundaries are too close for the resistivity tools to be sufficiently sensitive. Using this technique the geometry of the well can be deduced.
LOGS FROM THE FIELD

Log 1: The black ring on the GR and NGS logs indicates a zone of probable shale. The EPT is affected by occasional bad hole (poor pad contact) - red ring. The same hole rugosity problem causes a skip in the sonic response, blue rings.

Log 2: The Neutron Density (log 2) logs detect shale at the same depth as the GR (log 1) - see arrows - indicating that the shale bed is approaching from below the well. The blue circle highlights a probable change from sand to a mix of sand and dolomite (the heavier mineral causing the density to increase).

Log 3: Separation throughout the ‘shaly’ zone (identified by the tools in logs 1 and 2) is ringed in yellow and could be affecting a thin bed on the medium induction response. The region ringed in blue has the resistivity increasing while the GR, B_n, pb show shale. This tends to support the idea of a thin bed. The red ring highlights the cyclic rugosity caused by turbo drilling.

Log 4: The resistivity image is not an FMS type borehole picture. The resistivity curves have a depth of investigation comparable to the medium induction curve. Around the shale bed (blue ring), three pads read high while the fourth goes low, reacting to the shale. Lower down, the bad borehole conditions (due to the mud unit) make some pads lose contact with the borehole wall and read only mud (red ring).

Log 5: Raw data taken from logs 1 - 4 has been combined at the computing centre to produce this final evaluation. The lithology ringed in red may represent only a thin bed. Porosity is low as the neutron-density readings are affected by the shale layer. They are not reading the same formation as the deep reading resistivity logs, hence the computed saturation will be incorrect. Dolomite has also been identified (ringed in black) as predicted above.

The long and winding road

Coiled tubing has been used in wells for a number of years for services such as nitrogen displacement or for spotting stimulation fluids. The tubing comes in many sizes with standard reels being 11/4" or 11/2" diameter. As horizontal wells started to proliferate, it became necessary to find a method of conveying slim hole devices into completed wells. Coiled tubing offered the best possibility and so cables were installed inside the tubing.

This task has its own peculiar difficulties because the cable cannot be installed while the tubing is on the reel. The sequence of events is:

• Find a straight, level stretch of land such as a road or desert, about 5km long.
• Lay out the coiled tubing.
• Attach a ‘pig’ to the end of the logging cable.
• Pump the pig down the coiled tubing, reeling out the cable very carefully until it reaches the other end.
• Reel up the coiled tubing and make the electrical connections.

Far-fetched as this sounds, it has been done, even on a roadside in Europe. Normally, this operation is performed in the manufacturing plant.

When producer and injector wells are surveyed, the pressure on the wellhead needs to be contained. The standard wireline system is useless and the coiled tubing set-up has to be installed. This involves a great deal of planning and equipment seen in figure 3.25 and 3.26.

Once in the well, the operation proceeds like any logging job. A large number of logging services have been run to date using this method including production logging, TDT logging, Water Flow Logging (WFL*) and perforation.

An important aspect of any operation, especially in horizontal wells, is pre-job planning. With coiled tubing, the ‘tubing’ is particularly pressing as the tubing itself is subject to numerous forces. These cause the tubing to bend and finally lock up in the well. The depth of lock-up is needed in advance of logging to establish whether the operation is feasible.

Dowell Schlumberger has researched this topic in detail culminating in a program called CoICADE† which computes the lock-up depth. The inputs are borehole profile and tool combination. The output gives the maximum depth that the configuration can run into the hole (figure 3.27).

Keeping in contact

Horizontal wells are usually drilled as far as possible from problem areas such as oil-water or gas-oil contacts. In fact, this is sometimes the specific objective. However, monitoring movements in these contacts is still important to predict possible problems before they occur.

The TDT* tool is used in vertical wells to monitor saturation changes in the reservoir during the production life of a well. It can be used in exactly the same mode in horizontal wells. The tool is not focussed and hence measures all around the borehole. In this way water encroachment or gas coning can be seen.

Finding the best profile

The Production Logging (PLT*) tool consists of a number of sensors used to determine the flow profile and fluid distribution in a well. The main sensors are:

• Spinner, to measure flow rate
• Temperature sensor
• Pressure sensor
• Gradiometer, to measure fluid density.

The first three sensors work in the horizontal case. However, the gradiometer employs two pressure sensors, a fixed distance apart, to compute the fluid density. When the tool is horizontal, there is no longer a vertical distance between the transducers and hence the tool will not function. With the tool’s remaining three sensors it is impossible to obtain the fluid distribution. A secondary sensor is needed such as a hold-up meter or a nuclear fluid densimeter.

† Mark of Dowell Schlumberger

Both have been tried in a horizontal environment with mixed results. The nuclear tool is often ruled out because it contains a chemical source, which would cause the operator problems should the tool be lost in the well. The hold up meter appears to be confused whenever there are turbulent zones, a frequent occurrence.

Fortunately there is another option. The current TDT tool, the Dual-Burst® TDT, not only measures the capture cross section of the formation, but also that of the borehole. This measurement clearly shows the difference between fluids - salt water reads 120 cu, oil 25 cu and gas 5 cu-10 cu. It is possible to scale this output in terms of borehole salinity and also to compute a pseudo-density to identify the fluid in place. This has proved to be a multi-function tool and by recording the tool in the WFL configuration the interpreter can measure water flow alone. Comparing this with the total flow measured by the spinners enables the flow of other phases to be calculated.

These methods work very well in cemented liners and barefoot completions. In slotted liner wells there is an additional problem, flow on the outside of the liner itself. Here a WFL log reacts to the total water flow, both inside and outside, while the flowmeter measures only the flow inside the liner. Interpretation of this type of completion needs care, and even with the best possible information can only be an estimate.

The Water Flow Log technique (described in Middle East Well Evaluation Review Number 8) uses a TDT-P tool as neutron emitter, and detector of the resulting gamma rays. Having three detectors in the standard tool string - the near and far detectors of the tool itself, plus the GR set about 15 ft away from the source - allows a wide range to the measurement, about 1.8 l/min to 200 l/min (figure 3.28). The tool can be used to measure water upflow or downflow. In the latter case the tool string is inverted (figure 3.29).
Fig. 3.30: An example of production logging in a horizontal well including the TDT Borehole Sigma curve. The hole profile in the first track shows two low spots on the trajectory. A fluid velocity (track three) has been computed using the spinner data. It shows an increasing flow along the well to a maximum value just below the casing shoe. There is an anomaly between 1,820m and 1,755m where the flow decreases and is erratic. The ‘fluid density’ (track four) shows two strange zones, 2,050m-1,960m and 1,820m-1,755m. These intervals coincide with the lows in the well trajectory. The first could be a zone of low oil production, below the spinner threshold, with the oil gathering at the low point. The second interval probably indicates caves behind the slotted liner, with most of the flow disappearing at this point. It reappears from time to time, finally coming back to its original value as the borehole comes back into shape.

Fig. 3.31: A similar case to figure 3.28, only this time the uncertainties caused by flow outside the slotted line are resolved by using a Water Flow Log. Stations were made along the well and a water flow rate was computed. This was then used in conjunction with the spinner-derived total flowrate to obtain the fluid mix. The results are shown in track three.