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Real-time Formation Evaluation for Optimal Decision Making While Drilling: Examples from the Southern North Sea

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ABSTRACT

In recent years, rapid growth in horizontal-well completions has been driven by the need to reduce field-development costs. Logging-while-drilling (LWD) technology and geosteering techniques have advanced to ensure high rates of success in reaching reservoir targets that are smaller and less clearly defined than those attempted previously. Three recent examples illustrate the benefits of these techniques where LWD data are acquired at the rig site, transmitted real time to the operator's office, and interpreted by a multidisciplinary asset team that updates formation models to enable optimal geosteering decisions.

Prior to drilling the horizontal wells, forward modeling based on offset-well data and structural information from the earth model is used to predict LWD log responses along the well trajectory. While drilling, the formation model is refined to minimize spatial uncertainties within the reservoir and to provide a predictive model of the formation relative to the wellpath. This refinement is achieved by correlating the real-time LWD logs with forward-modeled log responses. Resulting correlations constrain the position of the bit in the formation, so apparent formation dip can be computed. Synthetic LWD logs are predicted for the projected trajectory 150 ft (45 m) ahead of the bit. Uncertainties in the formation structural model are reduced further by interpreting LWD azimuthal density images retrieved between bit runs. These are processed immediately on a workstation in the operator's office and provide dip information to constrain the structural interpretation and interpretations of lateral differences in stratigraphic thickness. Image data also provide information about facies and help in identifying zones of high permeability.

Three case studies show how geosteering based on predictive real-time modeling can help manage risk associated with drilling horizontal wells by reducing uncertainties about positioning. They also show how optimizing placement of wells improves productivity of wells.

INTRODUCTION

As a result of the need to reduce field-development costs, nearly all wells drilled in the southern North Sea are completed horizontally. New technologies have made drilling and logging these wells less difficult; therefore, fields previously marginal are now economic to develop. Geosteering—defined as the real-time steering of high-angle and horizontal wells using while-drilling data—has been developed to ensure higher rates of success in reaching reservoir targets that are smaller and less clearly defined than those attempted previously (Lesso and Kashikar, 1996). Geosteering allows wells to be guided to optimal geological destinations, rather than simply to be steered directionally to predetermined geometric (not necessarily optimal) locations.

New LWD resistivity tools provide as many as 20 resistivity logs. Azimuthal LWD resistivity and density data can provide azimuthal borehole images, dip information, and a plethora of formation-evaluation data. However, the problem the operator faces is making the greatest use of data within the tight time constraints of drilling. The true value of LWD data for making decisions is realized fully when the data are used for interpretation while drilling. Updating the structural and petrophysical model of the reservoir in real time allows corrective geosteering in response to observed changes in the reservoir, which in turn allows the remaining wellpath to be optimized. Therefore, real-time interpretation can be applied as a means for the operator to derive more benefit from the LWD data and so manage risk by reduction of uncertainties about positioning.

This paper aims to show how the value of LWD data is increased when the interpretation is accomplished within a real-time decision window. Case studies described below are from recent work on three gas-development wells in the southern North Sea.

BEFORE-THE-JOB PREPARATION

Forward Modeling

Logging-tool response to a layered medium depends on the angle between the tool axis and the bedding plane. In the case of horizontal wells, this angular relationship can lead to difficulties in interpreting data from resistivity devices, particularly when adjacent-bed effects are complicated by fluid invasion and anisotropic formations. Forward modeling of logs provides insight into possible log responses in a particular well by constructing a catalogue of modeled logs for a range of scenarios that show geology and trajectories. The Integrated Forward Modelling (INFORM*) system provides this facility (Allen et al., 1995). This system enables selection of the optimal LWD-tool configuration and demonstrates feasibility of the well-geosteering requirement. It also familiarizes the asset team with log responses expected in different geologic scenarios and makes the team alert to geometry-dependant events such as polarization horns.

Pilot-well or adjacent-well log data are used to build one or more "layer columns" to represent the stratigraphic sequence in the planned well. Offset-well log data—in these cases, Rt (true resistivity), bulk density, neutron porosity, and gamma ray—are run through deconvolution filters to produce squared log responses. Deconvolution reduces the number of layers sampled to only those at actual petrophysical differences. It also enables the analyst to include thin beds that have not been resolved properly in the original logs but which may be significant during geosteering correlation.

The 3-D structural model of the reservoir is combined with the petrophysical stratigraphic column and the proposed well trajectory. Then the petrophysical model is convolved with the LWD-tool response functions to generate synthetic logs along the planned trajectory. Typically, various geologic and structural models are run to visualize uncertainties associated with input data, such as different formation dips and potential faults. Forward modeling produces a database of the modeled LWD log responses from 0° to 90° apparent dip. This database is exported to a PC system for use with geosteering software.

In the "landing" of some wells, predicted lithology and thickness and actual lithology and thickness are significantly different. In these cases the landing data are used to update the stratigraphic column of the model, and a new database of log responses is generated for the geosteering software. (This was required in Case Study 2; upon landing the well, an extra bed of shale was penetrated. *Landing* is the location at which the well trajectory reaches horizontal, 90° deviation.)

Design of Logging Program

The gamma-ray log is the main correlation log used for landing the well and for identifying major paleohorizontal markers in gas reservoirs of the southern North Sea. Resistivity logs are used primarily for estimation of gas saturation and locally as indicators of distance from the upper boundary of the formation. Density- and neutron-porosity logs are used for inferences about reservoir quality and fluid type. In case studies described here, the logging programs involved an integrated LWD system of 2-MHz (megahertz) resistivity, gamma-ray, and azimuthal density-neutron tools mounted directly behind a steerable motor (Figure 1).

The 2-MHz array-resistivity device (ARC5*) has five transmitters and records five phase-shift and five attenuation borehole-compensated resistivities, along with a gamma-ray log (Bonner et al., 1995). The azimuthal density-neutron tool (ADN4*) is equipped with an integral blade stabilizer, to minimize standoff from the borehole wall, and magnetometers that allow orientation of measurements (Holenka et al., 1995; Carpenter et al., 1997). As the tool rotates, the density and photoelectric-factor (PEF) data are binned into 16 equal sectors around the borehole. These 16 sectors are used to generate oriented density and PEF images of the borehole, which are interpreted manually to calculate bedding-plane dip and azimuth, and to gain information about lithofacies. The 16-sector density data are averaged radially to produce quadrant density and average density.

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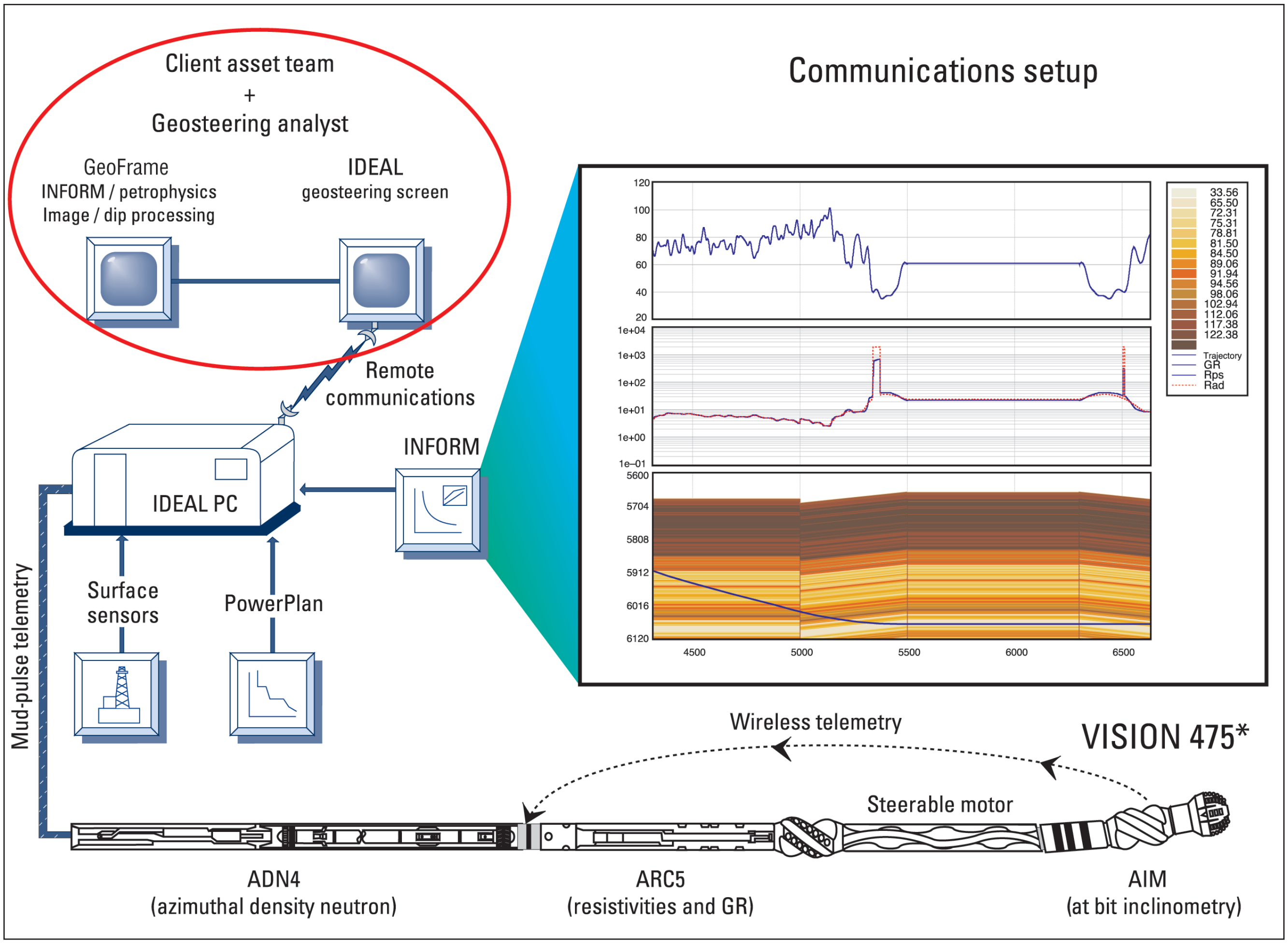

Figure 1. Geosteering communications setup. Data are transferred by mud-pulse telemetry to the IDEAL* acquisition unit at the surface and real time by satellite to the office-based PC.

During drilling, the amount of data that can be transmitted to the surface by measurement while drilling (MWD) telemetry in real time is limited; therefore, a tool configuration containing the most significant curves generally is selected. For the three case studies described below, the real-time (transmitted) data typically included the gamma ray, density quadrant up (ROBU), density quadrant down (ROBB), and resistivities of Phase Shift 34, 10-in. (25.4 cm) (PS34 and PS10) and attenuation 34-in. (86.4 cm) (AT34). The real-time density-up and density-down quadrant data can be useful for determining whether the well is cutting the stratigraphic section upward (i.e., toward younger strata) or downward.

COMMUNICATIONS SETUP

Hardware

A robust link between the rig site and the PC used by the office-based interpretation team is a critical part of the geosteering process. The general communications setup is shown in Figure 1. Data are transferred real time to the office-based PC, which displays the depth log and directional driller's "tool-face" display as seen on the rig. This PC is used for the geosteering correlation work and is networked to a workstation that is used for petrophysical analysis and for processing and interpretation of the density and PEF images.

REAL-TIME INTERPRETATION

Geosteering Software

The core of modeling work is achieved by building a 2-D structural model of the formation while drilling. This model minimizes spatial uncertainties and provides a predictive model of the formation relative to the wellpath. This "correlation" model is built on the basis of PC geosteering software. The real-time LWD log data and MWD well trajectory are displayed with a forward-modeled synthetic log drawn from the database modeled before the job. Resulting correlations indicate the actual position of the bit in beds of the formation and provide a synthetic LWD response for the trajectory projected 150 ft (45 m) ahead of the bit; thus, the

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wellpath can be replanned if necessary. Different formation models can be applied easily, and faults can be integrated in models of the formations.

Memory Data Processing

Using real-time LWD density- or resistivity-imaging tools can reduce the number of uncertainties associated with the structural model built by geosteering software. Data sets from these imaging tools, too large to be transmitted real time, can be downloaded between bit runs and processed on the petrophysical workstation. The borehole-azimuth images are analyzed interactively to provide structural dip information for confirming and constraining the structural correlation model. Even if the density data are of quality insufficient to estimate dips, in most instances, the form of bedding on images permits a decision as to whether the well is being drilled upward or downward through the stratigraphic succession.

In addition to generating image data, LWD memory data (normally of higher resolution than the transmitted data) can be processed for estimates of porosity and saturation. In case studies described below, the wells had objectives in terms of cumulative porosity feet, a figure updated with the memory LWD data between bit runs. The ten different resistivity measurements on the ARC5 allow an evaluation of Rt that accounts for the effects of invasion and anisotropy. The key is to process memory data quickly, so that information gained can be used to help optimize placement of the well in the remainder of the stratigraphic section.

Data Distribution

Results of the geosteering software correlation work, image interpretation, and petrophysical interpretation are distributed before operation meetings. In the third case study described below, the operator maintained a Web site, which enabled associated personnel offshore or onshore to access data and results.

CASE STUDY 1

Seismic depth-conversion problems, a poorly imaged fault about two-thirds of the way along the horizontal section, and limited well control in the area posed uncertainties in the position of the target. Uncertainties about depth were caused by variation in thickness and velocity of the Zechstein sequence, immediately above the reservoir. The purpose was to drill a 2500-ft (760-m) horizontal well in the upper portion of the Rotliegendes Upper Leman sandstone (Permian), maintaining a standoff from the gas-water contact.

The well was planned as a geometric placement, with no initial intention of geosteering. Using two offset wells, several structural-geology scenarios were modeled at the well-planning stage. The most probable "base-scenario" model is shown in Figure 2.

The correlation model built up over six days of drilling (Figure 3) shows the structural geology relative to the drilled trajectory and the planned trajectory. From the first two correlation points within the reservoir, dip was calculated to be about 1° and the well was landed successfully in reservoir Zone 1. A fault was predicted at about 1200 ft (350 m) into the horizontal section of the borehole. The fault was penetrated at about 700 ft (200 m); the borehole passed abruptly from the reservoir, through younger beds of the Zechstein, and into the overlying Werra Anhydrite (Figure 3). From the geosteering software model, the minimal fault throw was calculated to be 20 ft (6 m) and the dip of the anhydrite to be about 15°. The well was steered downward to try to regain the planned trajectory, but it did not reenter the reservoir. The well was allowed to descend until it reached the "hard-floor" standoff from the gas-water contact. At this stage, several hundred feet of anhydrite had been drilled and the well had not reentered the reservoir.

The geosteering model built from real-time data (Figure 3) indicated that the difference in total vertical depth (TVD) of the reservoir with respect to its position leftward from the fault (Figure 3) was 90 ft (27 m), rather than the 45 ft (14 m) predicted from seismic data. The geosteering model indicated that the wellbore was only several feet above the reservoir. At this point, the operator agreed to steer downward; the reservoir was penetrated 10 ft (3 m) TVD deeper. Apparent reservoir dip of 3.5° was calculated from new correlation points. The well was leveled off and remained in the pay zone to total depth. Geosteering of the last several hundred feet of the well increased the drain by 550 ft (168 m), or 45%, with respect to the planned trajectory. Initial production was 80% greater than projected.

A final refined model of the structural geology (Figure 4) was built from the LWD memory data. The operator used that interpretation to provide a structural framework for the reservoir-simulation model.

CASE STUDY 2

In the well described here as Case Study 2, uncertainty in seismic depth conversion resulted from heterogeneity of the thick Zechstein sequence, above the Lower Permian reservoir. The log-forward model (Figure 5) shows predicted structural geology; no faults were expected. A simple, horizontal-drain trajectory was planned, but contingency was left for geosteering.

The uncertainty in depth conversion was realized early in drilling the 6-in.-diameter (15-cm) section; correlations of the lower Zechstein indicated that the reservoir would be higher than predicted. In fact, the reservoir was 43 ft (13 m)

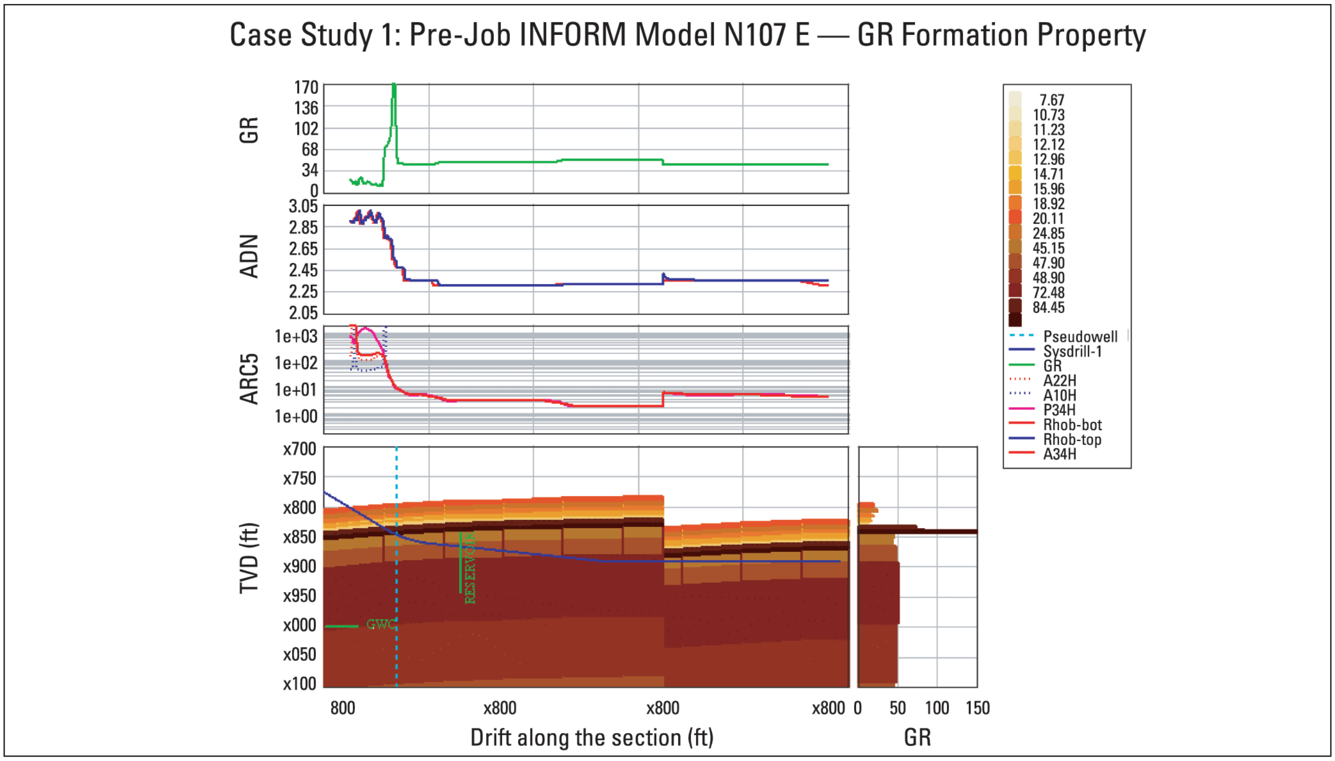

Figure 2. Before-the-job model, Case Study 1. Lowermost panel: Colors of formations based on scaling of gamma-ray signal. Dashed blue vertical line shows point of entry into reservoir. In descending order, upper three panels show forward-modeled gamma-ray log, density logs, and resistivity logs. TVDSS = true vertical depth subsea; ARC5 = compensated array resistivity tool; ADN = azimthal density neutron tool.

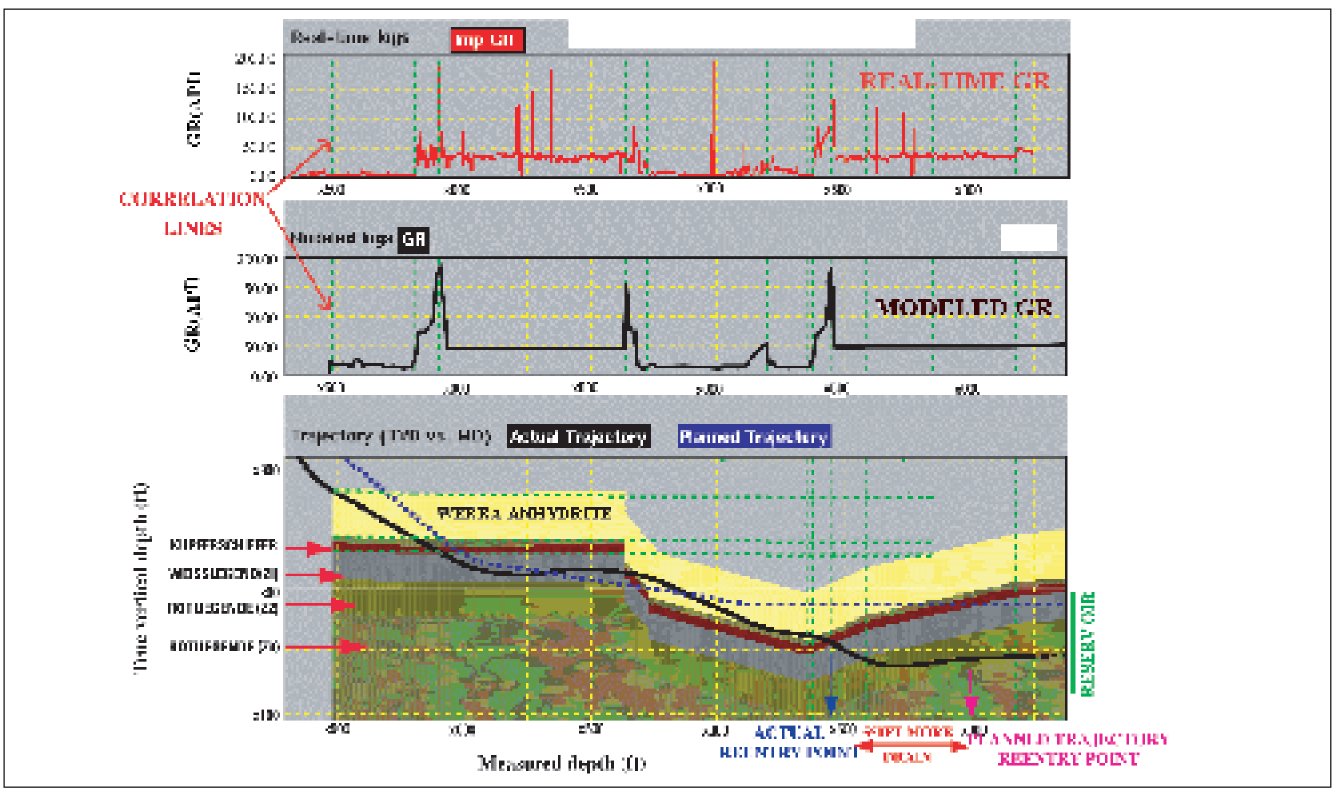

Figure 3. Case Study 1: Geosteering screen correlation model. Panels are described in descending order. Panel 1: real-time gamma-ray log. Panel 2: Modeled gamma-ray log. Panel 3: Cross section showing planned trajectory of well (blue dotted) and actual trajectory (black). TVD = true vertical depth; MD = measured depth.

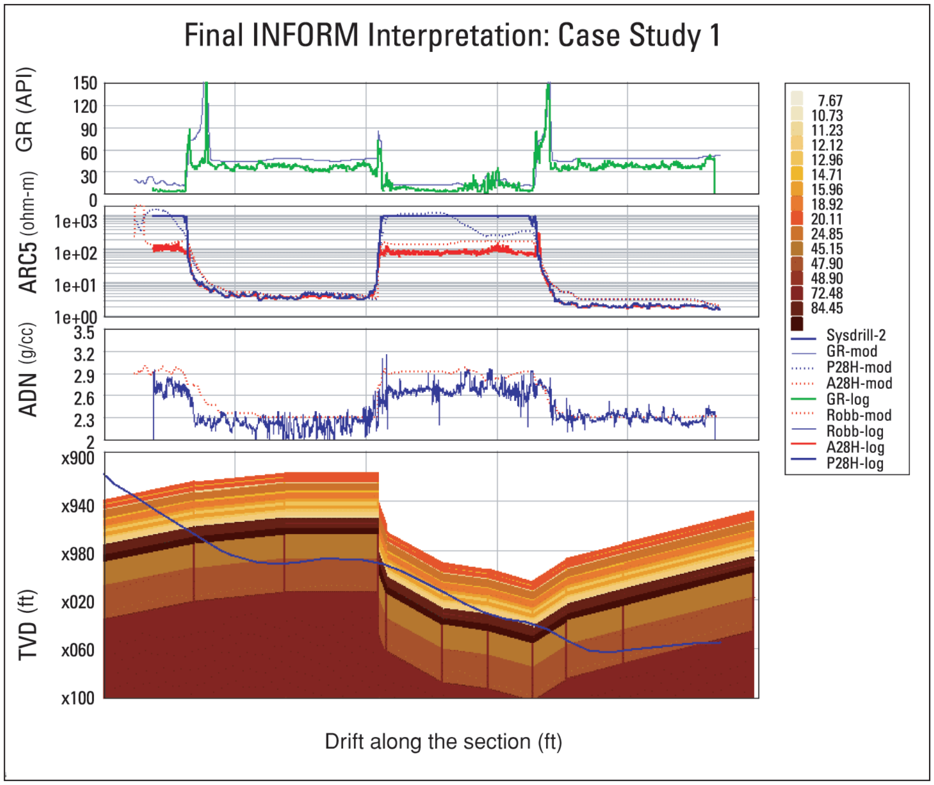

Figure 4. Case Study 1: final interpretation. Panels are described in descending order. Panel 1: gamma-ray logs; modeled log in blue; actual log in green. Y-axis scaled in API units. Panel 2: resistivity logs; modeled as shown by dotted lines; actual logs shown by solid lines. Panel 3: azimuthal density-neutron logs; modeled as shown by dotted line; actual log shown by solid line. Panel 4: after-the-job interpretation of stratigraphic sequence and structural geology. Sysdrill-2 = drilled trajectory; GR-mod = modeled GR; P28H-mod = modeled resistivity phase 28 inch; A28H = modeled resistivity attenuation 28 inch; ROBB-mod = modeled bottom density; GR-log = recorded GR log; ROBB-log = recorded bottom density log; A28H-log = recorded resistivity log phase 28 inch; P28H-log = recorded resisivity log attenuation 28 inch.

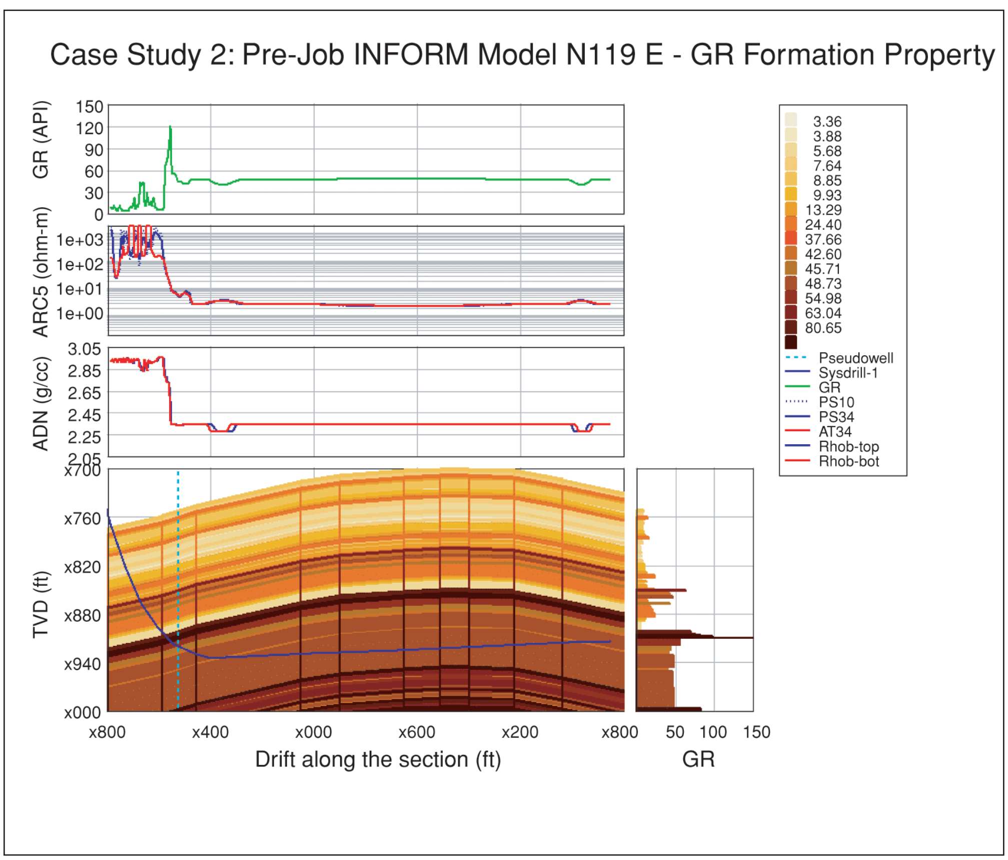

Figure 5. Case Study 2: upper set of three panels shows forward-modeled logs. In descending order, gamma-ray, resistivity, and density logs. Lowermost panel shows model of stratigraphic succession and structural geology. Solid blue line shows planned trajectory of wellbore; dashed blue line shows point of entry into reservoir.

higher than anticipated, but the well was landed correctly, 20 ft (6 m) TVD into the reservoir (Figure 6). The stratigraphy differed significantly from that of the offset well; an additional unit of shale was penetrated. The drill bit was changed after landing the well, and for the geosteering-software database, the memory LWD logs were used to update the upper portion of the reservoir model. When drilling recommenced, geosteering-software correlations indicated that strata dipped slightly toward the toe of the well, contradicting the dip expected from the seismic model (Figure 5). Additional correlations based on real-time gamma-ray and resistivity data (Figures 6 and 7) confirmed this dip and indicated that the well was approaching the top of the reservoir. A second bit trip was made and the azimuthal density image was processed, which confirmed that the well was drilling upward through the stratigraphic sequence. The wellpath was adjusted downward. Reference to the correlation model indicated that the adjustment avoided the well's penetrating the upper boundary of the reservoir by 2 ft (0.6 m), TVD (Figure 6). The remainder of the drain was drilled successfully in the upper portion of the reservoir; the well was drilled gradually downward through the stratigraphic sequence and then essentially bed-parallel for the last one-third of the horizontal trajectory (Figure 7). Tests showed initial production of 40% more than predicted.

CASE STUDY 3

At the outset, Case Study 3 involved two principal uncertainties: (1) Structural relief of the reservoir was not well known, and (2) the reservoir was comparatively thin (70 ft [21 m]) and of relatively indistinct petrophysical character. These uncertainties increased the risk of drilling through the top or bottom of the reservoir in the 2500-ft (760-m) horizontal section, because the position of the wellbore could be difficult to establish.

The offset well used to populate the petrophysical model was about 1.5 mi (2.4 km) from the heel of the well. Figure 8 illustrates the excellent correlation between the synthetic-log response and the real-time gamma-ray log, as displayed on the geosteering software. This correlation was the basis for a high level of confidence about the position of the well, which was landed within 6 in. (15 cm) vertically of the desired horizon.

At about 1500 ft (460 m) of horizontal section drilled, it became increasingly difficult to be certain of the bit's position in the formation, although the quality of the reservoir was acceptable. It became more difficult to slide with the mud motor, so the string was pulled and the drilling assembly was changed to a rotary system with a variable-gauge stabilizer. Thinness of the reservoir, uncertainty in the seismic depth

Figure 6. Case Study 2: upper set of two panels shows gamma-ray logs of the GeoSteering Screen correlation model, as labeled. Lowermost panel shows the updated model of the geologic cross section. The actual trajectory of the well is shown in black. Gamma-ray logs scaled in API units. TVD = true vertical depth (ft); MD = measured depth (ft).

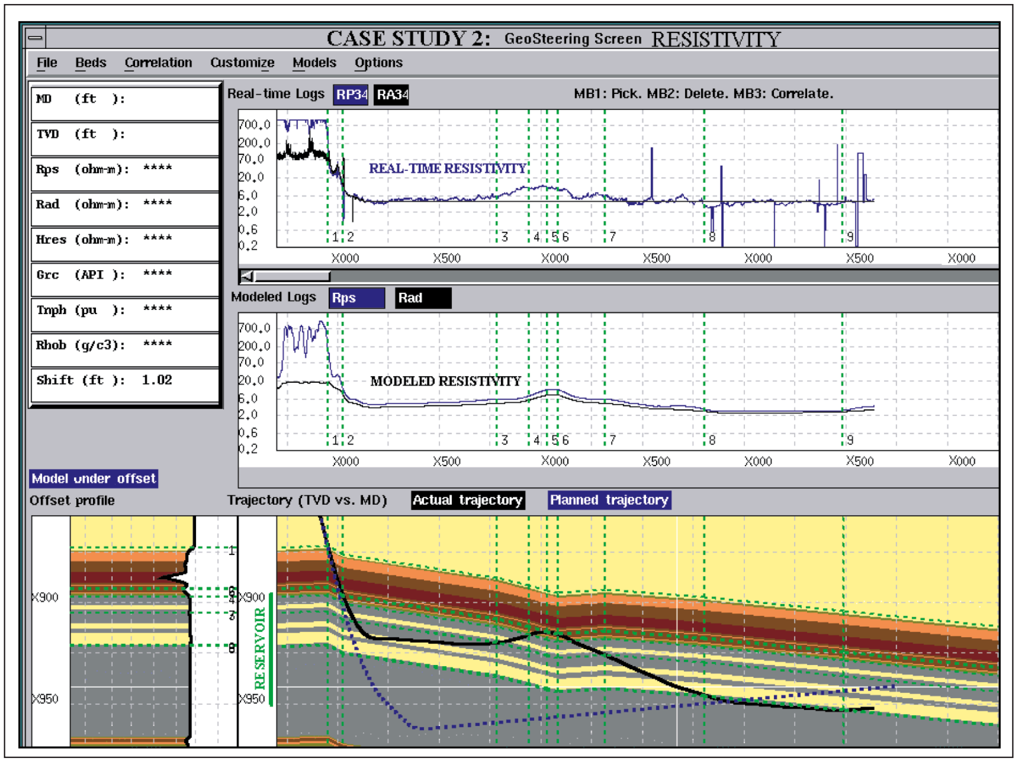

Figure 7. Case Study 2: upper set of two panels shows resistivity logs of the GeoSteering Screen correlation model, as labeled. Lowermost panel shows the updated model of the geologic cross section. The actual trajectory of the well is shown in black. Gamma-ray logs scaled in API units. TVD = true vertical depth (ft); MD = measured depth (ft).

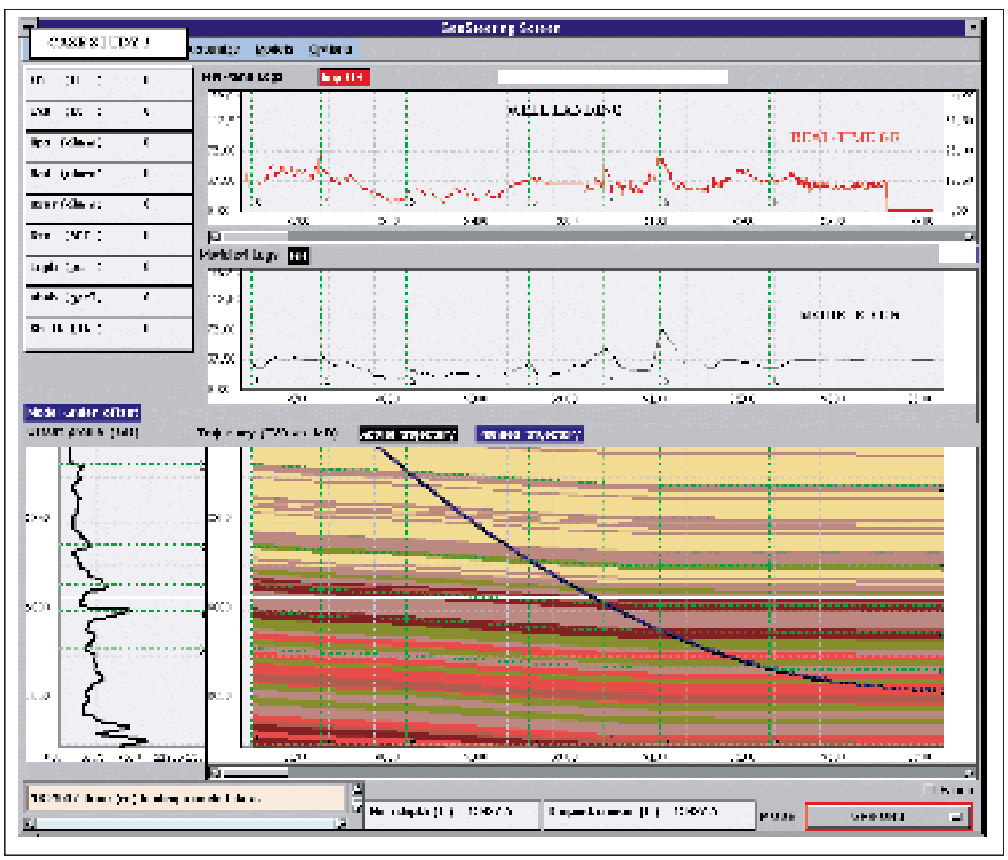

Figure 8. Case Study 3: upper set of two panels shows gamma-ray logs of the GeoSteering Screen correlation model, as labeled. Observe the excellent correlation between the synthetic gamma-ray log (black) and the real-time gamma-ray log (red). Gamma-ray logs scaled in API units. TVD = true vertical depth (ft); MD = measured depth (ft).

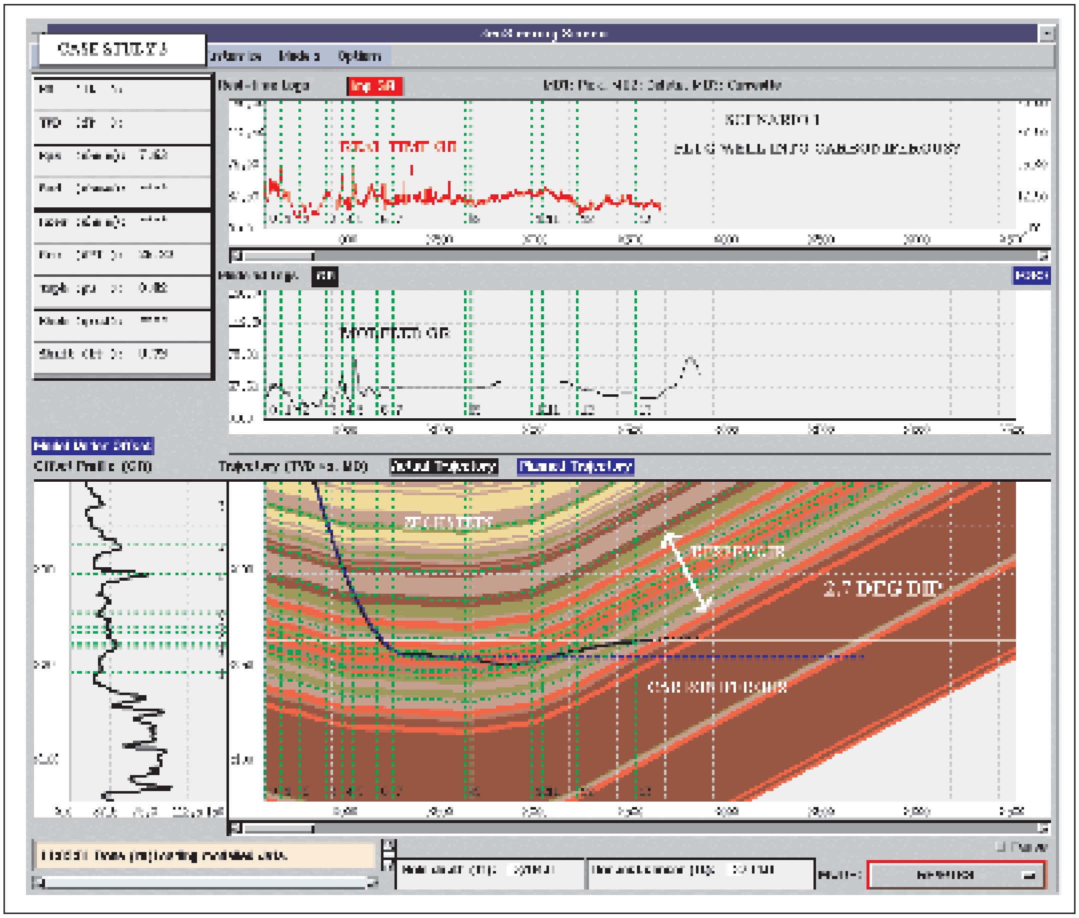

Figure 9. Case Study 3: upper set of two panels shows gamma-ray logs of the Geo-Steering Screen correlation model, as labeled. Lowermost panel shows Scenario 1, a correlation model developed after entry into the reservoir and after a bit trip. The model is based on hypothetical dip of -2.7°; penetration of the boundary between the reservoir and underlying Carboniferous strata is projected (dashed black line). Gamma-ray logs scaled in API units. TVD = true vertical depth (ft); MD = measured depth (ft).

conversion, and subtle contrast of beds within the reservoir increased the risk of drilling out the top or bottom of the reservoir. To have done so would have cost many days' rig time to plug the hole back and sidetrack it. Figures 9 through 11 show the three geosteering-software correlation models that were produced at the time of the bit trip. Figure 9 shows the formation dipping at -2.7° and models the well's potential entry into Carboniferous strata. Figure 10 models the formation dipping at 0.75° and the well approaching the top of the reservoir. Figure 11 shows the formation dipping at -1° and the well's being essentially bed parallel. Note that a difference in dip as subtle as 3.5 degrees (compare Figures 9 and 10) could result in the well's exit from the bottom or top of the reservoir. In this situation, close attention to positioning was critical.

On retrieval of memory data at the bit trip, azimuthal-density data (Figures 12 and 13) were processed and interpreted. The borehole trajectory relative to beds of the reservoir was interpreted from oriented density images. From 3830 ft (1168 m) measured depth (MD) for about 50 ft (15 m), the borehole essentially was parallel to beds of the reservoir. Through the next 75 ft (23 m), the borehole cut through a bed that is thinner than 6 in. (15 cm). Dip of this bed was calculated to be 1° southeastward and the well trajectory as N89°E. In the interval from 3980 ft to 4500 ft (1213 m to 1372 m) MD, the borehole cut through the stratigraphic section from older to younger beds, as shown by sinusoidal directions on the asimuthal density image (Figures 12 and 13). At 4550 ft (1388 m), the borehole was effectively parallel to bedding (Figure 13); the borehole just touched a bed from beneath, then cut the stratigraphic section from younger to older beds.

When this information was related to the structural model on geosteering software, the correct interpretation became evident (Figure 14). This provided the operator with an unequivocal interpretation of the position of the well relative to the formation. Drilling recommenced with a new bit. With risk of exiting the reservoir minimized, it was decided to steer downward to try to penetrate the lower portion of the reservoir and ensure drainage from these strata.

The density images also yielded important information related to facies. The reservoir is predominantly a fluvial sequence with some dune apron and dune slip-face facies; the latter generally is the more permeable. The dune slip-face facies can be seen clearly in images from 4275 to 4350 ft (1303 to 1326 m) MD (Figure 13); they show evidence of

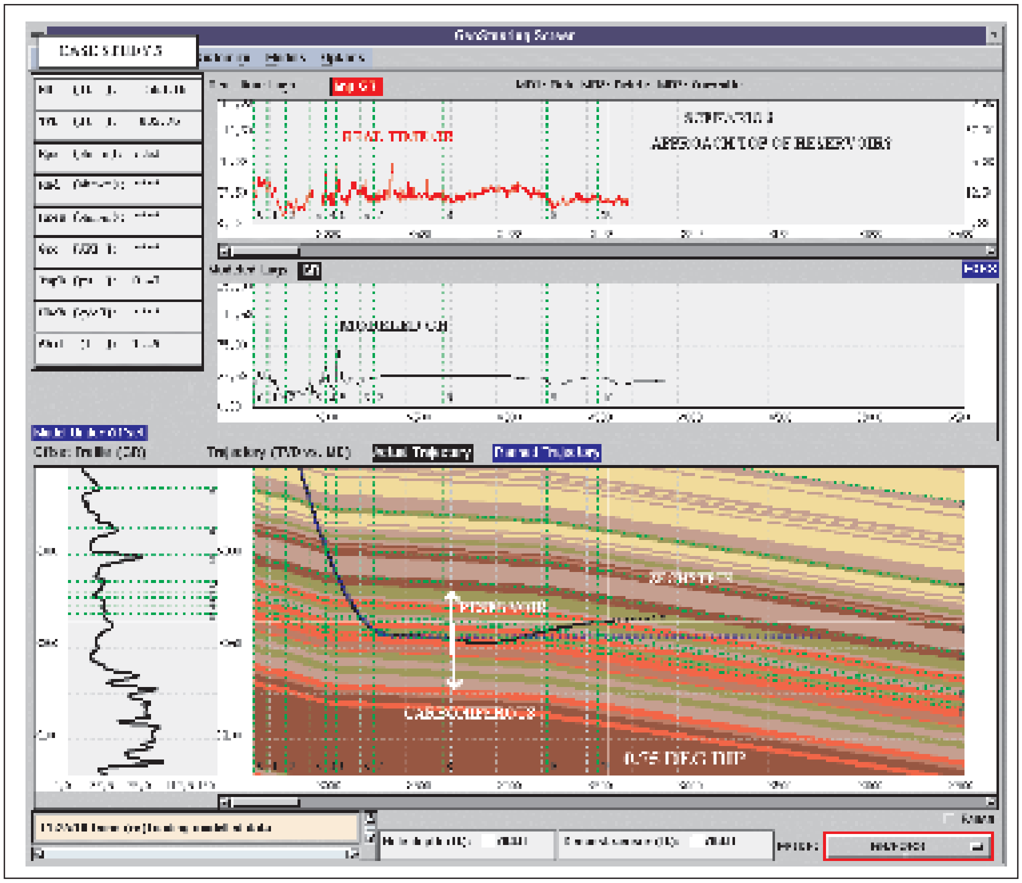

Figure 10. Case Study 3: upper set of two panels shows gamma-ray logs of the GeoSteering Screen correlation model, as labeled. Lowermost panel shows Scenario 2, a correlation model developed after entry into the reservoir and after a bit trip. The model is based on hypothetical dip of 0.75°; penetration of the boundary between the reservoir and overlying Permian strata is projected (dashed black line). Gamma-ray logs scaled in API units. TVD = true vertical depth (ft); MD = measured depth (ft).

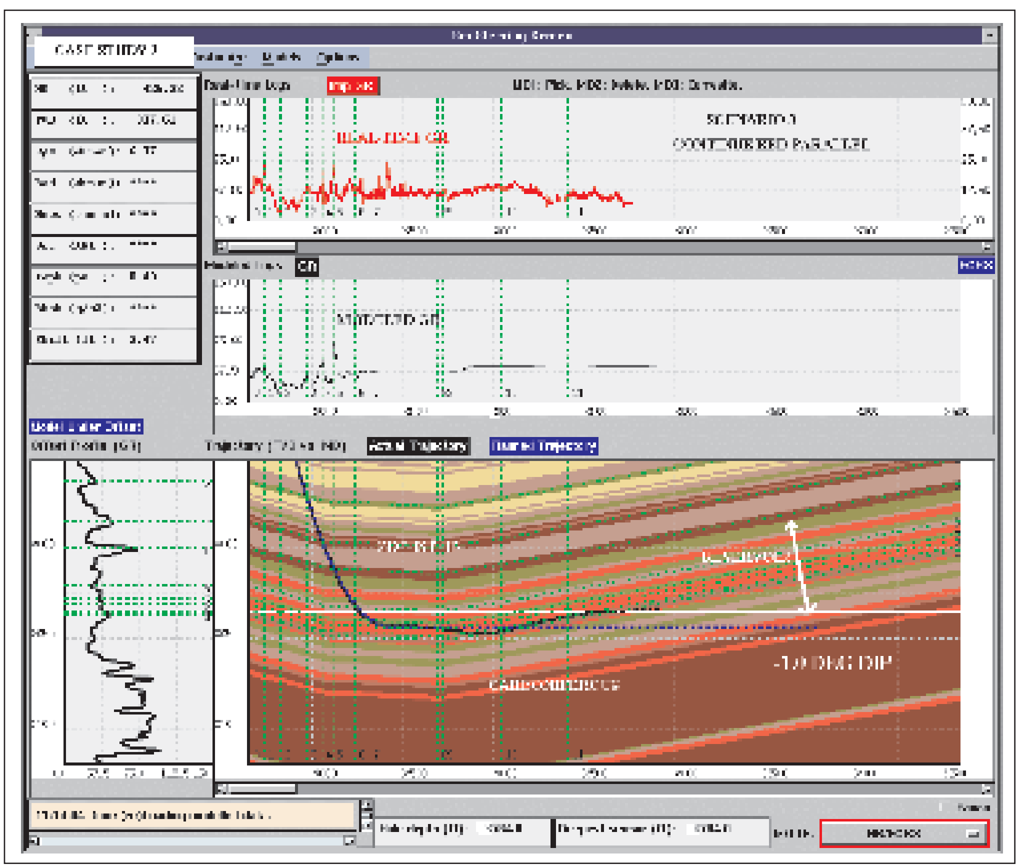

Figure 11. Case Study 3: upper set of two panels shows gamma-ray logs of the GeoSteering Screen correlation model, as labeled. Lowermost panel shows Scenario 3, a correlation model developed after entry into the reservoir and after a bit trip. The model is based on hypothetical dip of –1°; under these conditions, trajectory of the wellbore would be almost parallel to bedding of the reservoir (dashed black line). Gamma-ray logs scaled in API units. TVD = true vertical depth (ft); MD = measured depth (ft).

depositional dip of 20° to 30°. The direction of dip indicates southwestward paleotransport, consistent with other data from the field.

CONCLUSIONS

From these three case studies the following conclusions were reached:

1) Risk can be managed by real-time modeling of available LWD data, which reduces uncertainty about the position of the borehole.
2) Geosteering optimizes placement of wells and increases their production.
3) Azimuthal LWD image data are powerful tools for constraining the position of a well within a formation.
4) Achieving optimal well placement requires the following:
   - A multisensor suite of LWD data must be available to the office-based team, in real time. The team can monitor the trajectory continuously and, if necessary, incorporate the most recently acquired data, reinterpret the geological conditions, and replan the trajectory.
   - Before-the-job modeling and planning enable preparation for contingencies and reduction of uncertainty through evaluation of expected LWD responses.
   - A close, cooperative working relationship between the geosteering analyst and the operator asset team achieves a more effective and efficient decision-making process.

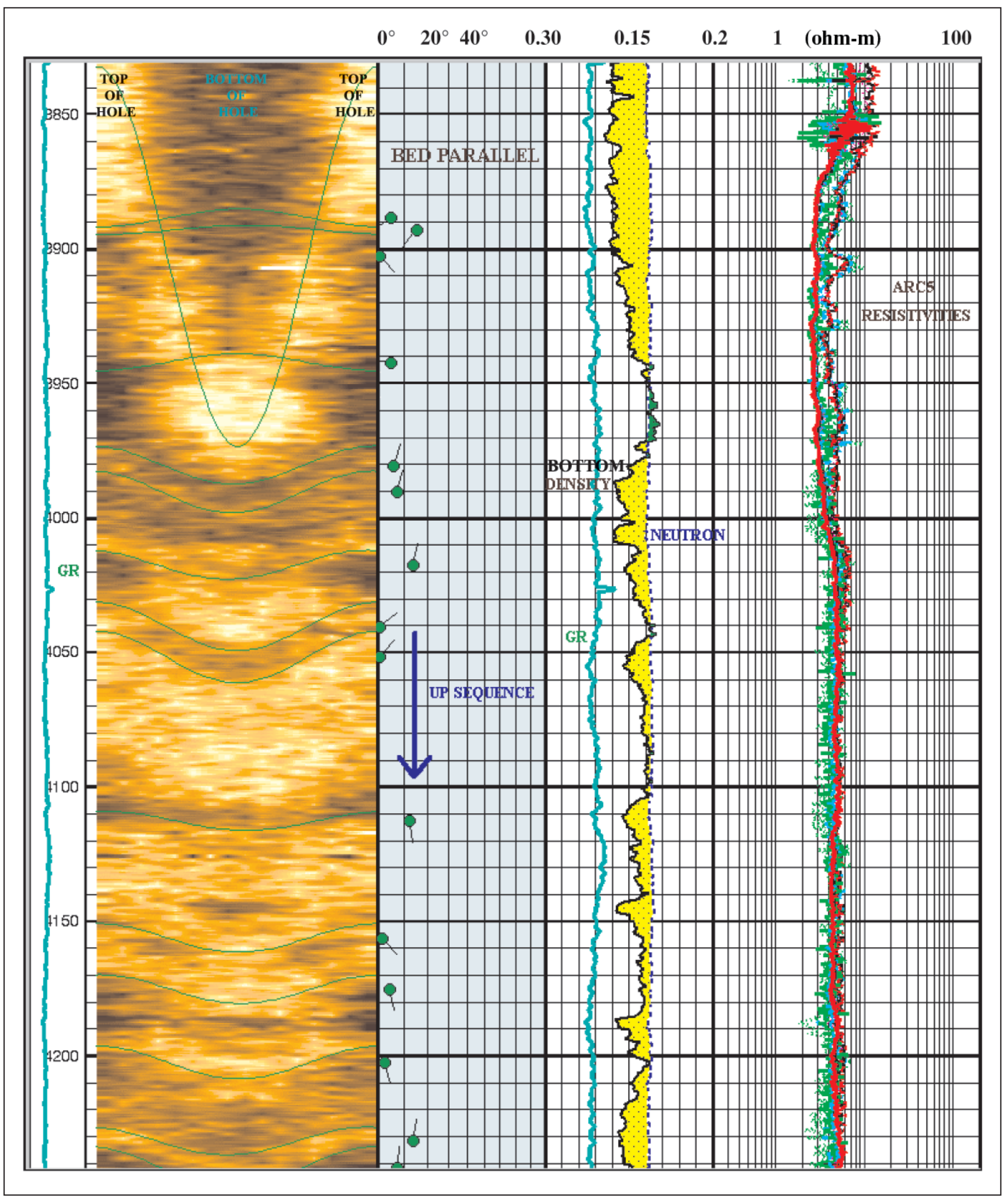

Figure 12. Case Study 3: azimuthal density image with LWD memory logs. Gamma-ray, density, neutron, and resistivity logs are shown as labeled. On azimuthal density log, light colors indicate rocks of high density; dark colors indicate rocks of low density. Sinusoidal green lines on azimuthal density image below about 3960 ft indicate that strata were penetrated in sequence from older to younger. Leftmost green line = suppressed gamma-ray log; blue dotted line = neutron log.

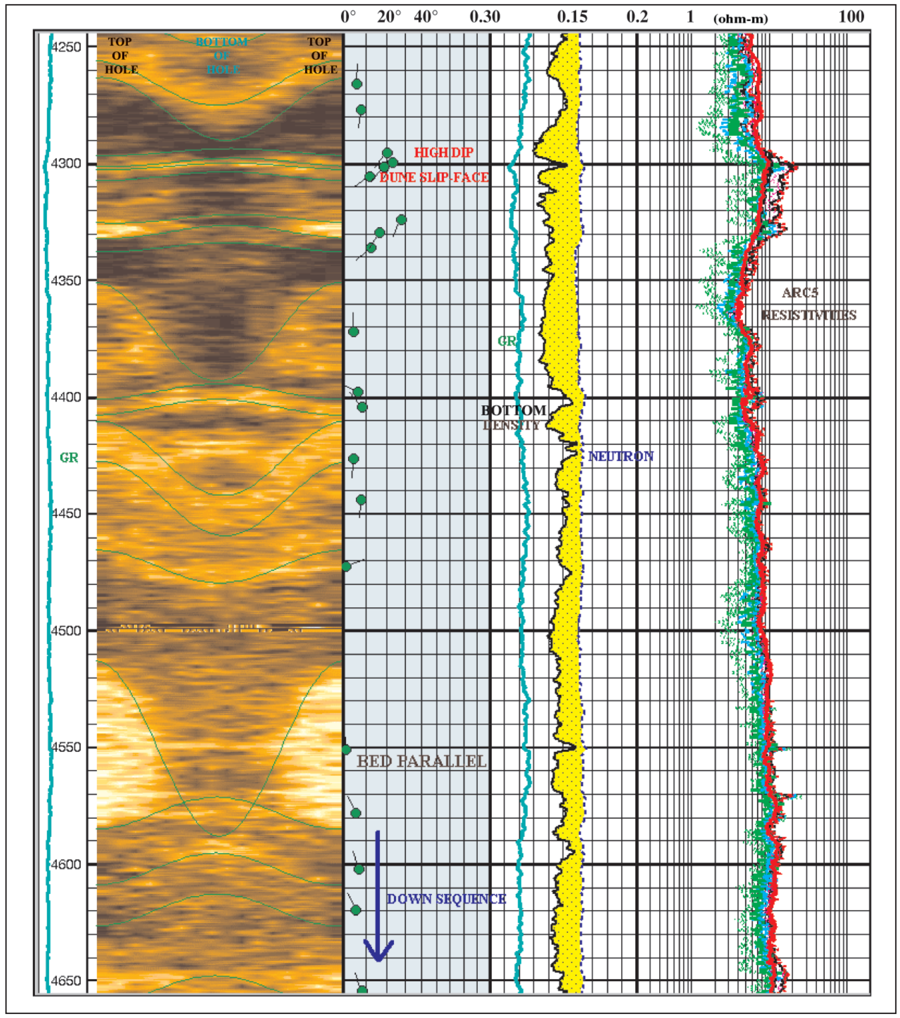

Figure 13. Case Study 3: azimuthal density image with LWD memory logs. Gamma-ray, density, neutron, and resistivity logs are shown as labeled. On azimuthal density log, light colors indicate rocks of high density; dark colors indicate rocks of low density. Wellbore cut strata in sequence from older to younger, to 4550 ft; at 4550 ft, wellbore was parallel to bedding, in contact with the base of a bed. Below 4550 ft, the wellbore penetrated beds from younger to older (compare azimuthal density images, Figures 13 and 14, and compare both to wellbore trajectory, Figure 14).

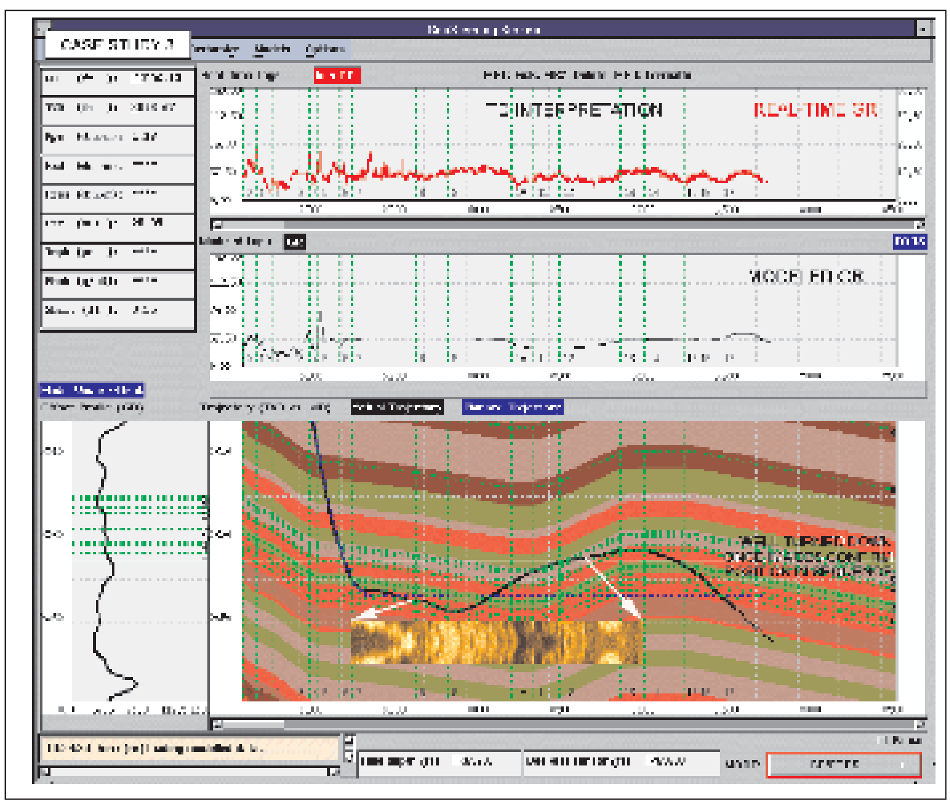

Figure 14. Case Study 3: final GeoSteering Screen correlation model, showing correct stratigraphic and structural interpretation. Upper two panels show gamma-ray logs, as labeled. Lowermost panel shows configuration of wellbore at position of bit trip (right-hand white arrow); from this position, the well was drilled downward, so as to penetrate the lower part of the reservoir. Relatively steep dips of beds from 4275 to 4350 ft are interpreted as evidence of sand-dune slip-face facies. Gamma-ray logs scaled in API units. TVD = true vertical depth (ft); MD = measured depth (ft).

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