Modeling Optimizes Completion Design

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HOUSTON—High water production is a major issue in horizontal oil wells, especially in longer laterals, commonly because of the high drawdown from the heel. In addition, the presence of heterogeneity along the lateral section can lead to uneven sweep of hydrocarbons, which can result in poor recovery. To control the water production and achieve better sweep efficiency, inflow control devices (ICDs) have been introduced that balance fluid flux along the producing horizontal well.

This article presents a case study of a Gulf of Mexico Shelf horizontal well that was completed with prepacked screens, and assesses the results of using integrated technologies such as ICDs along with rotary steerable drilling systems and azimuthal logging-while-drilling well placement technology to achieve higher reservoir sweep efficiency. The well was sanded in and plugged after five years of high water production. A saturation log was run in an offset well, which granted the viability to revisit this reservoir. Consequently, a new offset horizontal well was proposed and drilled next to the existing well to sweep remaining reserves.

For the new horizontal offset, full field dynamic simulations were performed to evaluate attic placement methodology and the optimization of ICDs into the integrated design. The results illustrate that attic horizontal well placement is feasible using integrated drilling with ICD technology to maximize the sweep efficiency.

In a mature field development, operators are challenged to place wells as high as possible to minimize attic traps and produce from the thin oil rims. Nevertheless, early water breakthrough is still a problem with such horizontal wells because of the imbalanced drawdown along the horizontal and the close proximity to the oil/water contact (OWC). In practice, to increase hydrocarbon recovery from these wells, flow rates are increased. This results in drawing higher localized water production that can cause “hot spots” in the completion string. Mechanical failure of the sand control media often follows, leading to well plugging.

To effectively exploit such reservoirs, it is necessary to geosteer horizontal wells as far as possible away from the OWC with the means to balance fluid influx along the horizontal. Developments in LWD technology have enabled structure or bed boundary mapping in real time to accurately place wells below the reservoir trap or within thin sand columns. Completion technology incorporating stand-
alone screens combined with customized downhole ICDs can be introduced to delay or regulate water breakthrough. While these technologies individually add value to horizontal well production, in combination, they provide the needed solution to optimize recovery and prolong the lifespan of a producing lateral well.

**Anticinal Reservoir**

The reservoir is located on the Outer Continental Shelf near the Louisiana Coast. It is a fluvial/deltaic sand deposited in shallow water. The reservoir is an anticline with a sealing fault to the east, as shown in Figure 1A. The north-to-south cross-section of the sand in Figure 1B shows the anticlinal structure of the reservoir. Sand thickness varies from 48 to 77 feet, and is thicker at the center of the reservoir. The sand is highly unconsolidated, making sand control integral to the completion strategy.

The unconsolidated sand is highly porous with an average porosity of 32 percent. The log data were upscaled to calculate a variogram, which showed major continuity in the northeast direction. The modeled variogram was then used as input to create the porosity model. The reservoir model is based on a cell size of 100 x 100 x 2 feet. Sequential Gaussian simulation was used to create the porosity model.

The permeability of the reservoir was modeled based on sidewall core analysis, which was used to find the correlation between porosity and permeability to model the permeability of the reservoir.

Figure 2A shows the core analysis with correlation and Figure 2B shows the modeled permeability that was eventually used in the flow simulations. The high permeability of the sand brings great production challenges for the wells in this reservoir as a result of the strong aquifer at the bottom. This is a matter of significant concern with horizontal wells because of the desired high production rates in a reservoir with high vertical-to-horizontal permeability ratios.

The oil-water capillary zone was neglected because of the reservoir’s high vertical permeability. Because of a lack of pressure-volume-temperature data, fluid correlations were used to create PVT tables. Oil gravity of 29 degrees API, gas specific gravity of 0.7, bubble point pressure, and initial fluid contacts were some of the key inputs for the fluid model. A black oil model was used for the flow simulations.
History Matching

The reservoir has three vertical wells and one horizontal. The first two vertical wells, V1 and V2, depleted most of the free gas cap. The horizontal well, H1, started producing more than 5,000 barrels of water and less than 200 barrels of oil a day after two months of production. The lateral section of well H1 was completed with prepacked screens that faced mechanical failures after four years because of possible hot spots in the screens caused by the high-rate water production.

Recent logging in an offset well revealed unswept hydrocarbons in place (Figure 3). Since the hydrocarbon interval is only 12 feet, the most viable approach is to place a horizontal well high within the pay. A new horizontal well, H2, was planned to be placed close to the H1 horizontal well. Two main challenges had to be addressed for the H2 horizontal well: placing the horizontal well in a 12-foot-thick pay zone and steering it away from the OWC, and delaying early water breakthrough and balancing fluid influx.

Even after placing the H2 well at the top of the structure, the recent resistivity log indicated that early water breakthrough was inevitable, given that the original OWC had moved up by 12 feet because of the high permeability and strong bottom-drive aquifer. To avoid early water breakthrough and high water cuts, an IC D completion design was considered. To model the ICDs and their behavior over time, it was important to understand the dynamics of the reservoir. Dynamic simulation incorporating pressure, saturation and reservoir heterogeneity was performed to optimize the ICD design for the H2 well.

Before modeling the ICDs, full-field history matching was performed to calibrate the fluid saturations, pressure and petrophysical properties. The black oil simulator was used for the history matching. The historic oil rate control was used as a development strategy along with a minimum bottom-hole pressure limit. Figure 4 shows the results of history matching analysis for the field. The simulated historic oil, water and gas rates were matched with the respective observed data. From Figure 4, the first two vertical wells (V1 and V2) produced most of the gas cap. Well V3 had high water production. It started producing in the late 1970s and was shut in after a decade of high water production. It came on line again in late 2007 and produced for a couple years.

The H1 horizontal well was completed with prepacked screens in early 1995. The well began producing at very high water rates, but it also had higher oil production compared with the vertical wells. Higher water production has been an issue in every well drilled in this sand because of the high vertical permeability, and this issue became severe in the case of the H1 wells. After more than four years of production, H1 was plugged because of sanding from a mechanical failure of the completion string.

The history match was also done on individual wells to assure the consistency of the simulation model. After matching the rates, observed pressure data were plotted against the simulated pressure.

Completion Design

After calibrating the reservoir model for pressure and saturations, production was forecast for the new H2 horizontal well. Based on the reservoir heterogeneity, the production challenges for a horizontal well can be described as friction pressure loss from toe to heel, and coning at the heel (large drawdown for long wells) in the case of homogeneous reservoirs, and high permeability layers, faults and fractures, and early water or gas breakthroughs in the case of heterogeneous reservoirs.

In this Gulf of Mexico Shelf application, the reservoir has relatively homogeneous sand, making water coning more likely to occur at the heel of the new horizontal well. Because of the higher vertical permeability, high water production was inevitable, even though the H2 well was planned to be landed on top of the structure. To delay/control high water cuts and sand production, ICDs along with gravel packing were planned as part of the completion design. For the forecast, four completion designs were compared to show the value of ICDs.

The most common ICD has a nozzle-
based design, with a nozzle in the front and a screen at the back to protect the nozzle from sand and debris. The nozzle diameter can be designed to control the pressure drop across it, and therefore, the fluid rate.

ICDs create a pressure differential across the screen such that the annulus pressure is greater than the tubing pressure. This lowers the drawdown pressure on the reservoir. By designing the ICDs correctly, the drawdown pressure balance across the length of the well can be achieved. To achieve this balance, sufficient pressure is needed at the heel to arrive at the same flow rate as the ICDs. This pressure can be delivered using a pump or gas lift.

In heterogeneous reservoirs where permeability varies significantly across the lateral, especially in fractured carbonates where fluid flow along the annulus between the completion tubing and well bore will take effect, packers can be used for segmentation to isolate zones. Unless ICDs are employed, the flow rate in each section will be roughly proportional to the section permeability. By adjusting the flow restriction in each section, the fluid flux can be balanced within the section and along the lateral from heel to toe.

Four completion designs were simulated: open-hole, gravel pack (GP), GP and ICD (GICD), and optimum ICD (OICD). Although open-hole completion is not practical in unconsolidated sand, it was used only as a base case for comparison. The open-hole lateral section is 8.5 inches in diameter and 750 feet long. The gravel pack completion has a 4.5-inch screen in a 750-foot lateral packed with gravel in the annulus. In the case of the GICD, the ICD joints are installed inside the gravel pack screen, with eight ICD joints geometrically distributed and each joint (12 meters long) separated by swellable packers for annulus isolation. The nozzle size of each ICD is 2 x 3 millimeters (two nozzles three millimeters in diameter).

The OICD completion design is similar to GICD, but the number of ICD joints and their configuration is designed based on permeability and saturations. In this case, 12 ICD joints were installed, separated by swellable packers (Figure 5). The first seven ICDs from the heel had the smallest nozzle sizes of 1 x 1.6 millimeters to prevent early water coning because of high permeability. The remaining five ICDs, installed closer to the toe, had nozzle sizes of 2 x 1.6 millimeters to allow the water to push oil at the toe section for higher sweep efficiency. Different nozzle sizes and packer configurations were simulated along the horizontal to compare the performances, and OICD configuration yielded the highest recovery.

The four completion designs were simulated dynamically for one year of production using the same reservoir controls, including reservoir volume controls and BHP limits. The GP and GICD produced the same volume of oil and water after one year of production because the ICD nozzles in the GICD completion scenario were all the same size and too big to control water coning.

In the case of OICD, the cumulative oil production was increased by 15 percent in one year compared with the GICD/GP because of the strategically selected nozzle sizes based on the permeability and saturation responses. Also, there was no increase in the cumulative water production after one year, indicating that OICD allowed the same water production, but it also helped push the oil. The key is to understand the geology and petrophysics that eventually help to optimize the ICD configuration.

An average pressure drop of 170 psi was achieved across the nozzles for the GICD completion. The pressure drop across each nozzle is proportional to the square of the fluid rates. In the OICD design, for the nozzles close to the heel, a very high pressure drop of more than 300 psi was achieved initially, which helped choke back the high rate moving fluids into the production tubing from the heel section, promoting water to displace oil through the nozzles closer to

![Structure Map from Offset Well Control](image)

![Undulated Profile of Well No. 1 Trajectory along Modeled Structure](image)
the toe for better sweep.

Well Placement

For this study, the well placement challenges were described in a feasibility phase that determined a fit-for-purpose bottom-hole assembly for drilling and steering measurements for both the landing and lateral.

The reservoir was evaluated for well placement or geosteering off a structure map (Figure 6). The target sand package was evaluated using a cross-section correlation of the offset well log data. The reservoir pay interval was defined as a seven- to 12-foot zone across these wells, which was further refined to a five-foot drilling target window. The property of the reservoir derived from the log data was used to generate a measurement response for populating a preconstructed structure to provide log response simulations along the proposed horizontal well.

In addition to generating a response log model for the planned lateral, the offset lateral (well No. 1) provided the means to study the structure model and properties using a pre-existing lateral to gain insights into the well’s structural profile and production history (Figure 7). The reservoir top boundary depicted by offset resistivity measurements is represented by the black line with the reservoir beneath it.

Based on this model, it is obvious that the well’s trajectory (drilled with a positive displacement mud motor) undulates to weave in and out of the top of the reservoir. This trajectory undulation may not be accurately represented since the reservoir top boundary was modeled with undulations to match the log with the structure property response. This can be explained by trajectory divergence from the actual when employing positive displacement motors, taking stationary survey measurements at fixed distances.

Based on this understanding, the trajectory could be more tortuous. Although well No. 1 was located high in the structure, the entire lateral was not placed within the zone. The sumps along the lateral may have caused a higher influx at the heel, consequently damaging the media that could have resulted in sand particle breach into the well that prematurely ended the well’s production life.

This assessment clearly justifies using a rotary steerable system to provide a smoother, less undulating well. Besides drilling and steering needs, near-bit measurements such as gamma ray and continuous inclination along with the closed-loop steering capacity to hold or maintain the angle of the well is instrumental to provide a smooth lateral profile for production and completion success.

Prior to placing the production hole, accurate landing within the five-foot target column was the initial obstacle. While utilizing RSS with gamma ray and continuous inclination measurements at the bit would be the ideal BHA configuration, positive displacement motors with measurements 30 feet or more behind the bit could be employed with strategic well placement methodologies. Continuous LWD and inclination measurements in combination with geosteering response modeling is critical to overcome structural and survey uncertainties while the well builds through the curve to land at a 90-degree inclination.

Higher Landing Precision

Based on offset well evaluations, the overburden can be distinguished and correlated with gamma ray while the five-foot target can be defined only using resistivity measurements. Therefore, LWD gamma ray and resistivity measurements were concluded as the minimum requirement for the landing phase, while azimuthal bed boundary mapping measurements would be the ideal measurements for engaging higher landing precision.

Since lateral placement high within the target for a maximum displacement from the OWC was critical to the success of the well, azimuthal resistivity measurement or a bed boundary mapper is essential. To validate this recommendation, the feasibility for engaging the bed boundary mapping measurement was evaluated by generating synthetically modeled responses from structure model properties. This was achieved by selecting fit-for-purpose azimuthal LWD measurements to simulate the responses for the horizontal well across the targeted reservoir. For this reservoir, the response simulations illustrated that azimuthal resistivity measurements from a proprietary LWD tool designed with tilted receiver coils could help achieve the primary objective of placing the well in the optimal distance from the OWC.

Figure 8 demonstrates that the bed boundary mapping tool is capable of detecting the upper boundary of the target sand five and a half feet away and the OWC eight feet TVD away from the well bore. The actual distances are a function of a resistivity profile that is computed in real time, where no variables or constants are needed to manipulate the bed-to-tool distances. The ability to map the formation’s bed boundary facilitates the means to proactively steer the well. This reduces well path tortuosity to facilitate the smooth running of the completion string and allows the production hole trajectory positioning objectives to be achieved.

The planned trajectory is placed in a geometrically updip structure to provide sensitivity from the conductive bed for the response analysis. The resistivity phase and directional curves in the first two tracks from the top in Figure 8 are simulated raw measurements from the bed boundary mapper, while resistivity and gamma ray are simulated standard log measurements. The dots in the azimuthal resistivity detection view represent
direction and distance of the conductive beds that are mapped, with blue above and red below the tool. The azimuthal resistivity canvas view shows these beds mapped for two boundaries, and the insert illustrates the distances from the tool to the bed.

To overcome the identified well placement and geosteering challenges, RSS with azimuthal resistivity bed boundary mapping measurements is the optimal choice for drilling and steering the curve and landing sections of the well. Azimuthal resistivity with bed boundary mapping enables precise lateral trajectory placement high within the target and maximum displacement from the OWC for optimum recovery using ICD completions. RSS with azimuthal resistivity bed boundary mapping measurements is essential to the success of this project.

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