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Combining MPD Technology With Horizontal Drilling Creates New Opportunities In Mature Onshore Fields

By R.G. "Bob" Knoll

CALGARY–The global oil and gas industry is experiencing a paradigm shift in respect to the true applicability, capability and operational risks associated with managed pressure drilling (MPD), with a major focus on offshore applications. It is now accepted that as the dynamic plays out, these methods will become more common and standard in many varied applications globally, including mature and low-cost assets onshore.

Since the introduction of flow-drilling horizontal wells in the Austin Chalk, the industry has been developing many novel underbalanced (UBD) and near-balance well construction methodologies. Efforts have been initiated over the past few years to help standardize terms, and a global effort is under way to group all these novel methods of nonconventional well construction under the term MPD.

Significant value-adding potential remains untapped in the lower-48, where on the order of 2 million vertical wells exist in mature and depleted oil and gas fields. If only 10 percent of these wells are viable candidates for re-exploitation with modern MPD and complex (nonvertical) well technology, a pool exceeding 200,000 opportunities may await.

The majority of these mature assets are operated by relatively small independent companies, and this potential remains untapped since many of the smaller independents inappropriately view both complex well design and MPD as "high end" technology suited only to the major multinationals exploiting elephant-sized fields offshore.

There are independent operators re-exploiting marginal fields onshore the lower-48 that have successfully customized a complex well/MPD application adding value to their specific assets. Two such applications were in south-central Illinois in old depleted light oil fields in the Waltersburg sand member.

First Horizontal MPD Well

The operator applied a combination of MPD and horizontal well technology to exploit the uppermost four to eight feet of oil-saturated sand in an 80-foot thick section that had been watered out during primary production from vertical wells. The original 10-acre spaced wells (circa 1950) would achieve initial productivities in the range of 50 barrels of oil a day, but would then rapidly decline and water out.

Figure 1 provides a type log of a vertical infill well, illustrating the higher oil saturation remaining in the upper four-five feet of sand just below the shale cap. This new vertical pilot well was drilled conventionally overbalanced, cored and logged and put on production after a drill stem test. The reservoir pressure was measured at 500 psi, very slightly depleted at this true vertical depth of ±2,000 feet. The new vertical pilot well would only achieve an initial productivity of an average of 5-10 bbl/d, declining rapidly over the first two months of production. This low inflow performance is believed to be the result of extreme drilling-induced invasive damaged occurring in the relatively higher-permeability oil-saturated upper interval.

A simple horizontal well, analytical reservoir screening mod-

FIGURE 1

Vertical Well Type Log (Well No. 1)

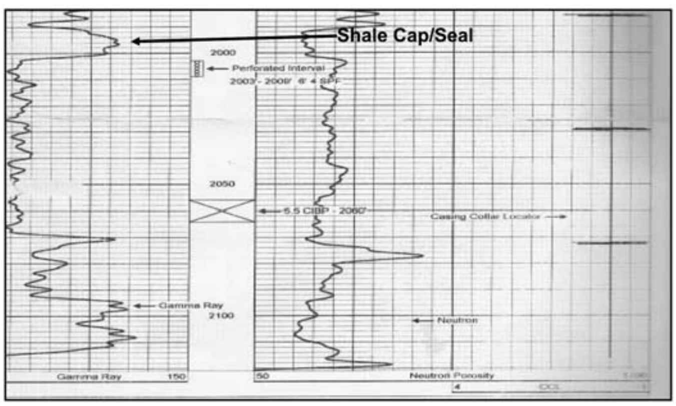
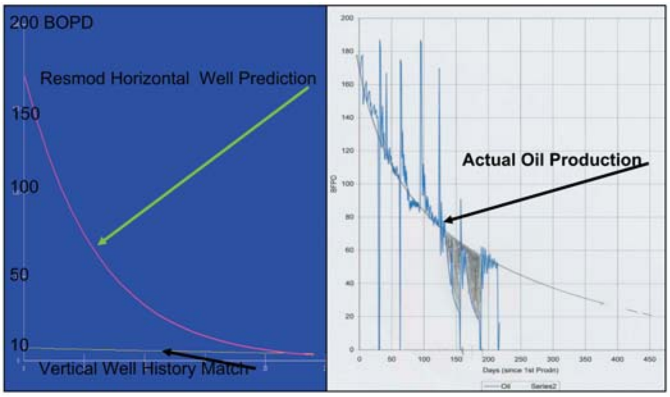


FIGURE 2

Predicted versus Actual Oil Production (Well No. 1)



el (Resmod-4™) was then employed to history match the new infill vertical well behavior, then predict the potential of a 1,100 foot-long horizontal well drilled with MPD as close to balance as possible to mitigate the invasive damage. A very comparable vertical well history match was accomplished with reservoir parameters similar to the data gained from the pilot well's log and core description, and reservoir pressure. The model predicted that a properly placed and undamaged (skin of 2) horizontal well should achieve an initial oil productivity of 180 bbl/d, declining to about 10 bbl/d after 18 months.

Based on these predictions, a new 1,100-foot horizontal infill well was placed between abandoned vertical wells. A simple KCl water-based drill-in fluid was lightened with air injection to keep the bottom-hole pressure as close to the reservoir pressure as possible. The MPD mode was chosen to both reduce invasive damage and mitigate inherent well construction challenges such as lost circulation and stuck pipe risks related to drilling horizontal intervals overbalanced in a depleted sand section. Corrosion was controlled at acceptable levels with the addition of corrosion reducers.

The well was placed along the top of the reservoir as planned by skipping below the top shale seal without any form of logging-while-drilling monitoring or e-log evaluation. Geosteering was based primarily on observations of oil/water inflow, cuttings staining and description, rate of penetration and bit response, etc. Very good oil-saturated samples were observed while drilling with a trace of light oil in the returned drill-in fluid. The well was completed as a six-inch open-hole below seven-inch casing landed in the sand target at 90-degree hole inclination just below the shale cap. A sucker rod pump was run and landed just above the "kick-off point" in the seven-inch casing and the well was put on production.

Figure 2 shows a comparison of the predicted (by the Resmod screening model) and actual horizontal well oil production over the first eight months. Note that the oil production and decline are very close to the predictions. Resmod is a simple single-phase model and does not consider water production. High water production and other unrelated operational issues led to occasional operational shutdowns illustrated in the decline curve. After 24 months of operation, the well had produced more than 24,000 barrels of oil and had paid out all capital and operating costs (about $750,000). The well is still producing 10 bbl/d at a very slight decline of both oil and water (800 barrels of water a day), and is projected to produce more than 28,000 barrels of total oil recovery at economic limits at current oil prices.

Many planning and operational lessons were learned on this application, but the key point is that a very small independent operator has generated value in an old depleted asset by properly applying complex MPD re-exploitation technology in a very low-cost environment.

Historically, drilling a well for only 28,000 barrels of total oil recovery from a five-foot thick depleted interval would have been considered economically unviable and highly risky. This field history demonstrates the potential to add value in this setting. It is expected that there are many similar settings and opportunities in many of the mature basins in the lower-48 states. However, there continues to be a number of applications where MPD attempts have failed or gained less than optimal results, from a technical and/or commercial standpoint, as was seen in the second project targeting the Waltersburg Sand.

Second Horizontal Well

Based on the success of the first horizontal well project, the operator pursued a similar re-exploitation tactic in a nearby field with a near identical reservoir setting in the same sand unit. This is a larger field with a similar production history from vertical wells drilled on 10-acre spacing and waterflooded as field pressure declined. Over its operating life, the field had produced 9 million barrels of oil, 200 million barrels of water and approximately 35 million barrels of river water had been injected. It was anticipated that the waterflood had preferentially swept the lower section of the 50-foot thick sand interval, leaving the upper four to six feet relatively unswept.

The objective was to place 2,100 feet of horizontal open-hole interval along the top of the sand, skipping below the shale seal with MPD to keep the BHP in a near-balance to underbalanced condition while drilling. Similar to the first case, no LWD or evaluation logging would be employed other then the addition of a pressure-while-drilling sensor on the BHA to confirm that the near-balance BHP target was being achieved.

Based on the historical data of individual well production and injected fluid volumes, the optimal location for an infill horizontal well was selected based on the area illustrating the best produced oil/water ratios. In efforts to confirm the lateral distribution of the target sand and to confirm that acceptable oil saturation still existed in the upper five feet of the sand interval, a vertical pilot was drilled within the planned horizontal well placement fairway, then cored and logged for reservoir description.

FIGURE 3

MPD Surface Equipment Setup (Well No. 2)

This vertical well was drilled conventionally overbalanced, the target sand interval was penetrated and the reservoir properties were observed as expected. This field has slightly superior properties than seen in the first case history, and the measured reservoir pressure was around 350 psi, a greater degree of depletion compared to the first well. Resmod predictions suggested a similar production response as seen in the first case if 2,000 feet of interval was properly placed and undamaged during construction.

After evaluating the vertical pilot, the horizontal well was drilled with a similar design as the first well. One alteration employed on this project was to use nitrogen instead of air to lighten the KCl drill-in fluid with a closed-loop surface separation system. This is a more intense and complicated arrangement of surface equipment than simple air injection and a large gas buster, and the amount of surface equipment and personnel required was significantly out of the ordinary for drilling activity in this area, as shown in the surface setup in Figure 3.

From an MPD application design perspective, and in hindsight, this setup was overengineered for what is required in an IADC MPD Level 1 setting (where the well is incapable of natural flow to surface, is "inherently stable" and is a low-level risk from a well control point of view).

Based on the low pressures, gas and oil in-flow rates observed during the construction of this well, the operator will either revert back to the more basic and less costly air injection/gas buster system in future wells in this field, or employ only produced water as the drill-in fluid and drill the well in a controlled overbalanced condition. The logic in this second option is an expectation that invasion by filtered connate water will result in an acceptable level of damage, but would significantly reduce capital costs and operational complexity. However, this would also present a well construction risk related to lost circulation and stuck pipe events, etc.

Operational Problem

In general, well construction activities went as planned once a series of closed-loop equipment setup issues were settled, (where/how to monitor produced gas and fluid volumes, how to collect surface samples, etc.). The one key operational problem experienced on this well was related to geosteering. Because of a series of operational errors and misunderstanding of long-term trajectory goals, the first portion of horizontal productive interval was placed 10-15 feet below the planned target TVD in the sand interval. This created a low spot at the heel and a slight slant-up design along the six-inch open-hole horizontal interval.

This geosteering error occurred in about six hours of rig activity, but may be the pivotal well design attribute that led to the possible economic failure of the well. This is a good illustration of the critical geosteering challenge faced in most horizontal infill applications, and is a dominant failure mode in many cases. Geosteering is not simply the use of high-end LWD tools and the employment of a "pay zone drilling specialist" in the horizontal construction phase. Properly applied, it demands a fully integrated and highly communicative team approach during all directional drilling phases to both find the moving geologic target, and also to effectively respond and properly modify the planned path as site-specific structural/geologic surprises are encountered.

One cannot express adequately the degree of geologic surprises encountered when placing horizontal intervals in "known" fields, and the resultant geosteering challenges that must be faced and overcome during these critical few days of complex well construction. This type of infill horizontal well cannot be drilled based solely on following a smooth line in a planned well trajectory plot. Any operator pursuing such an application should be ready to respond to surprises, and have the team prepared with contingency options considered and reviewed before field operations commence.

One interesting field observation in this case was the production of whole drilling mud in the return drill-in fluid as the productive interval passed within 60 feet laterally of the vertical pilot bottom-hole location. Since the horizontal interval was drilled with a water based drill-in fluid in a near balanced BHP condition, the only viable explanation of this whole mud observation is lateral invasion of this mud from the nearby pilot well, which had only three days of open-hole overbalance exposure during construction and testing. There were some thin intervals of sand seen in the pilot logs and cores, illustrating up to 900 milliDarcy of horizontal permeability.

It is believed that such an interval was invaded by mud while drilling the pilot to a depth of lateral invasion exceeding 60 feet, and this was the mud observed when the horizontal interval passed that distance away from the pilot well's bottom-hole location. This illustrates the extreme susceptibility to invasive damage this depleted sand interval has when using conventional overbalance well construction methods. This experience strongly supports the motivation to drill in a near-balance mode to mitigate this relatively irrevocable damage mechanism in horizontal well applications in depleted settings. Effectively managing this damage mode will be a critical factor of success in any such horizontal well infill application

The maintaining of a near-balanced pressure condition while drilling the horizontal interval was confirmed by BHA/BHP sensor readings and observations of water and oil inflow (up to 300 barrels of water a day was observed while drilling). However, detailed metering and measurement of produced oil and water volumes was difficult to impossible given the closed-loop surface system design, so the actual degree of underbalance generated at any one point along the well, or the actual inflow potential exposed at any given point was difficult to quantify.

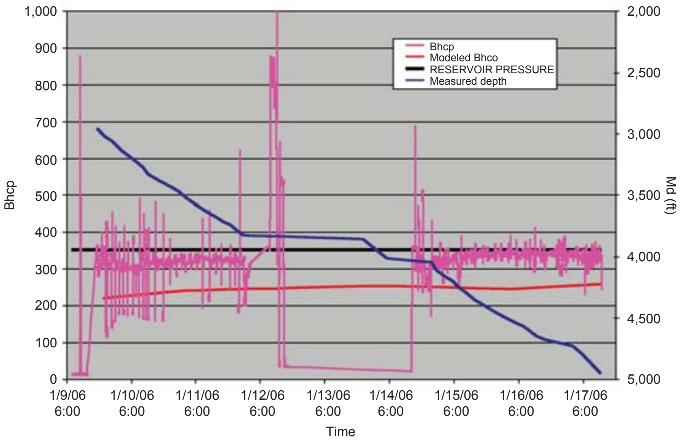
Critical Observations

A series of critical observations were noted in this field case that relate to the true ability to manage the BHP at targeted levels during horizontal well construction with multiphase drill-in fluids in pressure-depleted settings. Figure 4 offers an illustration of the predicted and actual BHP levels observed while drilling. There are two critical realities represented in this plot. The BHP was fluctuating dramatically in early time (left side of plot), showing BHP variation from a low of near 100 psi to a high exceeding 500 psi. This is an unavoidable result of compressive phase surging and slugging within the well during connections, tripping or other variations of drilling parameters necessary in all MPD operations.

All horizontal wells behave as very effective separators, so the surging dynamics can increase as well length is extended and varying reservoir quality is exposed. Note that as field activity progressed, optimum MPD parameters were defined and applied to better control the BHP surges. This learning experience is clearly expressed by the smoothing of the BHP surges seen at the end section of the well (right side of plot).

FIGURE 4

Predicted versus Actual BHP (Well No. 2)



Courtesy of Weatherford

This BHP pressure dynamic may be unavoidable when constructing horizontal intervals in an MPD mode. Site-specific field trial and error is required in every case to get control of this dynamic. The level of field experience of the MPD provider is critical in this respect, and this core competency varies significantly among service provider field staff. The vast majority of smaller independent staff is not versed in the site-specific trial-and error required in any complex well MPD application.

A detailed prespud meeting is a must, including training and safety orientation sessions for all field staff. As part of this planning effort, an MPD model prediction should be reviewed, with contingencies and maximum acceptable parameter levels preset (i.e., maximum acceptable surface back pressure, oil and gas release rates, etc.) for any such application to be conducted safely and have a chance of economic success. Even with this preplanning, trial-and-error of operational parameters on site will always be necessary to get as close as possible to the intended conditions. The uncontrollable BHP dynamic is one reason maintaining a truly underbalanced BHP condition while constructing horizontal intervals is an elusive, if not impossible, objective in many cases.

Another critical reality is illustrated in respect to the accuracy of modeling or predicting the BHP dynamic. Note in Figure 4 that the actual BHP levels (magenta) are consistently above the predicted values (red/orange) all along the well. Even when running sensitivities to water inflow, various friction factors and operating parameters, the model could never match the actual BHP conditions observed with the bottom-hole pressure-while-drilling sensor. The author has observed similar results in many MPD applications monitored globally.

There are many commercial multiphase models available in the industry. All have specific strengths and weaknesses, and all have a degree of accuracy dependent on site-specific parameters and the setting. None are perfect for all settings, and none can exactly predict the BHP dynamic in any given setting because of all the downhole unknowns and site-specific operational variables. The operator must be aware of this modeling constraint when planning any application, and be prepared to alter operational parameters and BHP targets as site-specific trial and error is conducted in the field.

It must be noted that this application was very successful in obtaining reasonable levels of BHP control, particularly at the end of the well. The targeted BHP of 350 psi was only obtained by reducing the fluid pumping rate while maintaining constant backpressure and gas injection rate. In fact, the water injection rate was reduced below the minimum recommended by the mud motor provider, and the model predicted lower limit for good cuttings transport along the horizontal section. Even with the reduced liquid rate, the motor preformed adequately and hole cleaning was effective.

The well was drilled to target length with good oil-stained cuttings, water and oil inflow observed all along the productive interval. Regular pipe movement and short trips were employed to ensure good hole cleaning and reduce torque and drag to workable levels. The independent operator employed a third-party field supervisor with extensive horizontal MPD experience in both field cases. Having this experience onsite is a critical resource to successfully implement this form of complex well MPD re-exploitation.

Heel 'Short Circuit'

Finally, and most importantly, is the lesson learned on this well regarding the optimum MPD strategy as well construction activities vary from the base plan. The goal was to maintain a BHP of 350 psi to be near-balance with the reservoir pressure to avoid invasive damage. However, maintaining this BHP at the toe of the well as productive length was extended meant that the heel of the well must be exposed to an ever-diminishing BHP condition. This is caused by the increasing equivalent circulating density (ECD) effect as length is extended. If the extended length ECD effect is 70 psi, the heel must be exposed to 70 psi less BHP than the toe; thus maintaining a 350 psi BHP target at the toe relates to a 280 psi BHP condition at the heel. This can be expressed another way by saying that the heel must be exposed to a 70-psi drawdown while maintaining the toe at a 350-psi BHP at-balance condition.

This degree of drawdown, combined with an unavoidable 100 psi variance during connections, implies that the low-point heel of the well will see more drawdown while drilling the toe than is intended during the initial production of the well. In effect, a short-circuit drawdown condition has been deliberately applied at the low heel of the well, encouraging premature water breakthrough at that point before drilling operations are completed. This "short circuit" effect may have been observed in the field as water inflow increased while the length was extended, but the inability to accurately monitor water inflow increase may have masked that observation.

In any case, this heel short circuit did occur, as seen in the early production performance of the well. The actual production behavior indicates strong water inflow from the heel, possibly preventing oil inflow from the slanted-up mid and end sections of the well. An interesting reservoir management challenge is raised by this behavior. Should the operator pursue high-volume lift of water in hopes that the resultant pressure decline will eventually allow oil to inflow from the farther intervals of the well? Or should a workover be performed to try to shut off the heel short circuit?

The fact that the well is an open-hole completed design is advantageous, in that numerous options are available should the operator attempt to seal the heel of the well (i.e., open-hole packer on tubing extension, swell packers or liners of various designs). Before pursuing that option, the operator has installed a high-rate ESP to lower reservoir pressure in hopes that the increased relative drawdown will eventually lead to increased oil production via an "inverse coning" response. The very early well production response to this high-volume lift tactic is encouraging.

The key point is that the intent to maintain a near-balance BHP condition along the total length of the well may not have been optimum, if not counterproductive, in this particular case. This was particularly worrisome once the heel was placed low in the target interval. Better oil production may have been gained by allowing a slight increase in BHP to counteract for the ECD effect on the low heel as well length was extended. The water-based drill-in fluid was selected in hopes that it would generate less invasive damage versus a conventional drilling mud.

Perhaps a slight overbalance BHP condition may have been acceptable at the toe as a trade-off to avoid the "short circuit" promoting increased drawdown expressed at the low heel. Applying MPD may often have a more complex impact than simply reducing pressure overbalance in depleted settings. This experience clearly demonstrates that MPD BHP objectives must be considered in detail and in connection with planned and actual well profiles, completion attributes and contingencies, reservoir management, and long-term production and workover strategies.

Key Findings

The key findings from these two similar field cases include the fact that considerable re-exploitation potential exists in the numerous marginal and depleted oil and gas fields in the lower-48 states. This potential can be realized by properly applying a combination of complex well infill drilling with nondamaging MPD well construction practices. By properly leveraging these technologies, and with high commodity prices, even extremely thin and dramatically depleted mature fields can be re-exploited to add value and increase ultimate reserves.

Many of these marginal assets are operated by small independents in very low-cost environments. Most of these entities lack core competencies in applying complex MPD well construction technologies. These independents are often hesitant to consider the potential based on a belief that this form of well construction is too complicated and expensive for a low-cost setting. However, a minimal investment in time, engineering resources and technical training is all that is required to arm the small independent with enough technical competencies to pursue these applications. Simple analytical models are available that accurately predict potential site-specific horizontal infill well performance so that the user can define reasonable net present value goals prior to initiating relatively expensive and complex well construction investments.

Another key finding is that defining, designing and optimizing MPD operations will always require a degree of site-specific trial and error to deal with the unavoidable BHP dynamics. No multiphase models are available that can exactly predict and account for all the site-specific reservoir and operational variables when applying complex well MPD construction in depleted infill applications. The degree of core competency and understanding of the BHP dynamics and required field trial and error steps varies dramatically within the ranks of key service providers and independent operator field staffs. Properly staged and documented prespud meetings and training of rig crews is a critical element for safety and success in these applications. Employing a BHP sensor on the BHA and fine monitoring of produced fluids, liquid-to-gas ratios, and applied backpressure will provide critical insights to optimize MPD parameters on a site-specific basis.

These two projects also demonstrated that geosteering remains a dominant failure mode in these applications. Many smaller independents are unaware of the degree of reservoir and structural surprises that are encountered when horizontally infill drilling in known fields, and the continued misunderstanding and operational errors occurring related to directional drilling standard practices versus site-specific geosteering requirements. Choosing and properly communicating the right geosteering strategy for a particular application is always a key, as is "keeping it simple" since the low-cost setting will normally not support high-end LWD geosteering solutions. The asset team must consider all possible observations and contingencies, and be ready to respond to surprises during those critical few days of complex well construction.

Another important point illustrated in these projects is that MPD can be safely and cost-effectively applied in low-cost marginal settings. Surface equipment selection and layout is often an issue that is overlooked, but must be fully reviewed and planned with all stakeholders prior to mobilizing equipment. In many of these re-exploitation applications, an IADC MPD level one setting exists, so that air and gas busters may be all that is required (keeping it simple). When using air, corrosion mitigation is always an important operational concern.

The final consideration is that the concept of constructing a horizontal interval in a maintained underbalanced condition in depleted settings is an illusive, if not impossible, goal. One key reason for this is the relatively unavoidable BHP dynamic occurring with multiphase fluids in a horizontal separator. Given that operational challenge, drilling a productive interval with a slight overbalance BHP objective with a nondamaging drill-in fluid may be a better tactic. The optimum BHP objectives must be site-specifically determined, and be adjustable given actual well paths, operational parameter trial and error variation, and the planned completion and production strategies to be applied over the life of the well. ❐

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