PERMIAN BASIN OPERATOR OUTPERFORMS COMPETITORS THROUGH ENGINEERED WORKFLOW COMPRISING COLLABORATION AND APPLIED TECHNOLOGY

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ABSTRACT

The Permian Basin (PB) presents many challenges in the development of unconventional plays, such as varying pore pressures, high treating pressures, and geological uncertainty. These challenges intensify in areas that are not well developed or understood. A collaborative partnership between the operator and service provider can significantly reduce such risks.

This paper discusses such a collaborative partnership in the PB wherein considerable benefits were achieved during drilling and completion of six wells. Using lessons learned and new technologies, the operator and the stimulation service company engineered a workflow to overcome challenges and deliver economic results that significantly outperformed previous wells. Key challenges faced and how they were overcome are discussed.

These efforts resulted in a six-month cumulative barrel of oil equivalent (BOE) increase of 32% from offset wells. The foundation of this success is directly attributed to the collaborative partnership between the operator and service company using an engineered workflow to achieve a common goal.

INTRODUCTION

Drilling and completing a successful unconventional well in the PB is often plagued by many unique challenges. The vast area that the basin covers can present challenges resulting from the geologic changes encountered from one area to the next. It is not uncommon to find that drilling and completion methods that work well in a specific area need to be modified significantly to successfully complete a well in another area. Indeed, it has been well noted by several PB operators that the odds of completing good, economically viable wells are, in many cases, strongly tied to the ability and willingness to adapt to the changes observed from area to area and play to play. Meeting these challenges in a timely and efficient manner usually requires significant experience and engineering resources. For smaller independent operators, this can prove to be a serious challenge.

Multinational and large independent operators generally have a vast support system of engineering tools and local expertise at their disposal. As such, these companies, on the whole, have an advantage over smaller independent operators in that they can address the drilling and completion issues that arise in new areas in a faster and more comprehensive manner. The end result is that they can often achieve economically successful wells much earlier in the life of the project, which in turn ultimately leads to a more successful development of the asset as a whole.

An operator drilling in northern Culberson County, Texas experienced these challenges firsthand. Previously, the operator had been successfully completing shallower conventional plays in their area for many years, only to encounter many of the issues previously outlined when it began to explore its unconventional assets. The operator drilled and completed several unconventional wells in the Wolfcamp formation using techniques that, at the time, were thought to be the best. Unfortunately, the wells proved to be uneconomical and difficult to complete. However, given the exceptional petrophysical analysis from log and core data, along with an increasing number of successful wells in offset acreage, the operator felt compelled to make a second attempt to realize the potential success of the play.

Having a long-standing relationship with its service company and knowing the ample tools and expertise available there, the operator approached the service company with the prospect of a collaborative and technical partnership. In the partnership, both operator and service provider would combine their knowledge and resources in an iterative engineered workflow (Figure 1) to achieve success in developing a play that was not yet well-explored. This paper examines many of the key issues that faced the partnership and how they were overcome to achieve success.

LESSONS LEARNED

To better understand and address the issues immediately facing the project, it was essential that both teams collaborate early in the process. The operator brought knowledge from the previously completed wells, as well as their years of experience operating in the area. They also conveyed information gained by other operators that had recently completed wells with varying success in the area. For its part, the service company was able to provide expertise of the region, as well as more current completion trends and practices that, when applied accurately to a zone of interest, were proven differentiators in other areas. From this collaboration, several key aspects of the drilling were first re-examined, including the lateral landing horizon as well as direction. The previous wells had been completed in differing horizons at differing azimuths. Another key part of the re-examination centered around the fracturing design. Previous stimulations had consisted of full crosslinked gel systems and ceramic proppant. Moving forward, these design parameters became crucial areas of review for the team. With new insight on the area, as well as evolving completion approaches in the basin, the team was able to draft several initial recommendations for improvement well in advance of drilling. This initial review of lessons learned proved to be a crucial starting point in the project. Because of the initial collaboration, both teams were able to meet required challenges because they each now worked from an equal level of experience and capability.

DRILLING

An increasingly important component of any successful unconventional completion is the physical drilling of the well itself. Most traditional approaches by companies, large and small, divide the drilling and completions into two separate tasks completed by two separate entities within a given organization. That being said, many organizations are discovering the value of bringing their respective drillers, geologists, and completion engineers together to exchange thoughts and ideas. Each group being aware of the challenges the other must address and design for allows all groups to work together to achieve the ultimate goal of producing the best well.

Drillers are often given a “depth window” in which to maintain the drilling path as the lateral is drilled yet are often not given a preferred contingency path if conditions cause the need to deviate. Would they be equipped with such contingent plans, the drillers, as issues arose, could strategically steer the borehole in the best direction to not only get back on track of the original drilling plan but also optimize the path for the subsequent completion in the process, thereby staying “in zone” as well as making the adjustments necessary to maintain the planned course of the wellbore. For this reason, the joint technical team (JTT) for the project elected to design a drilling plan that would incorporate both aggressive preplanning, as well as a broad range of contingencies as drilling issues arose. This was, of course, with each contingency focused on the well completion as a whole, not just the drilling aspect.

In the re-examination of the petrophysical log data, it was determined that the span of the initial completions was too broad in nature. The original paths of the wells were designed to exploit several different potentially productive zones in the strata rather than a single highly productive zone. To simplify the well design and focus on the most productive layer(s), pilot holes were drilled on the initial wells and extensive log analysis was performed. The analysis was focused mainly on porosity, total organic content (TOC), and brittleness; this resulted in a much more defined landing point for subsequent horizontal laterals. Further analysis indicated that the direction of the laterals should be altered to maximize the probability of inducing fractures transversely along the lateral. Additionally, the enhanced understanding of the horizontal strata gained from the pilot holes made it possible to design the drilling procedure to keep the lateral in the most potentially productive zones, despite any drilling issues that would occur. By following this strategy, the drillers were able to deliver wellbores that were predominantly placed in not only more producible rock but also in rock that was more easily stimulated.

PRE-COMPLETION REVIEW

As with the drilling of the initial wells, the JTT wanted to ensure that the initial completion designs incorporated the lessons of previous wells as well as more current practices and technologies. A key design aspect centered on the individual stage completions across the lateral. Rather than using simple geometric spacing of stages and clusters, the team elected to take a more engineered approach by also using information from the lateral itself. Undoubtedly, having horizontal log information can be advantageous in selecting exactly where to place the fractures. However, obtaining useful data from the horizontal can often be difficult because of time requirements and costs. It can also be exceptionally risky in the case of openhole logging of the lateral after drilling. Tool losses and unstable borehole environments can, in certain cases, lead to the loss of the entire lateral. For these reasons, it was decided to run cased-hole logging tools and process the data to derive pseudo-openhole properties with low risk. Clusters and stages could then be arranged strategically along the wellbore based on the derived properties, such as brittleness, TOC, and porosity.

Another well-documented concern of multi-cluster horizontal completions is cluster inefficiency within individual stages. Certain clusters might take less of the treatment than others, and in some cases, none of it at all because of insufficient breakdown. By taking advantage of limited entry cluster design and acid-soluble cement, the initial breakdown of the stage can be engineered to provide a better, more uniform opening of each cluster. This practice, coupled with the strategic placement of the clusters, would help ensure that each stage would break down more effectively and that each cluster would be treated more evenly.

The treatment stimulation design was also a key point of re-examination. Slickwater and hybrid designs had become increasingly common and successful across the unconventional plays of the basin. Given that the initial wells did not seem to respond favorably to crosslinked gel designs, the team elected to use optimized slickwater treatment. The proppant would consist of a 100- and 40/70-mesh white sand combination pumped at lower concentrations, which is standard for slickwater treatments. To optimize the treatment chemistry, formation rock and fluid samples were tested with different treatment chemical combinations. From the testing, the designers were able to select the friction reducer, surfactant, and clay-control components that were the most compatible and beneficial for the formation.

Post-treatment sand production, a basin-wide issue, was one more challenge the team wanted to address in the design. The use of resin-coated proppant in the later part of the stages as a means of dealing with this issue is widely applied in many areas. However, its application is often too costly and unreliable to provide adequate help. Instead, a specific surface modification agent (SMA) was chosen as a more preferred and cost effective option to mitigate sand flowback. This SMA works by coating the surface of the proppant grains, allowing them to adhere to one another and form a more cohesive proppant pack. To improve reliability, the amount and concentration of the SMA could be adjusted to achieve the desired level of performance.

REAL-TIME COMPLETION OPTIMIZATION

As previously stated, the willingness and ability to adapt to observed changes is often key in successfully completing unconventional wells. From the first stages of the initial treatment in the project, new developments were immediately discussed and addressed. Using real-time data analysis and pre-planned contingencies, the JTT was able to streamline the treatment design such that each stage became more easily pumped and more predictable.

Evaluation of each stage allowed the team to refine the limited entry and breakdown designs. Acid volumes and pumping rates were able to be adjusted on-the-fly to take advantage of the acid-soluble cement. These modifications drastically improved breakdown time, effectiveness, and average treating pressures as the stages progressed.

The proppant schedule was also enhanced incrementally. As with any slickwater design, the maximum sand concentration was limited because of reduced carrying capacity. Higher pumping rates can help, but only to a certain extent. Most standard slickwater treatments will struggle to pump sand effectively above concentrations of 2 pounds per gallon (ppg). To improve carrying capacity and deliverability, linear gel was added to the higher-concentration stages. Given the extra attention focused on ensuring all clusters were open and taking fluid, the gel was able to perform even more effectively. This enabled the team to pump higher concentrations and volumes of proppant than were previously thought possible. The maximum sand concentration of the treatments was able to be raised from roughly 2 to 4 ppg, and the proppant volumes were raised from 1,500 to 2,500 lbm per lateral foot treated.

ITERATIVE PROCESS

One of, if not the most significant, key to success in the partnership was the continued practice of reviewing the workflow, even after the initial successes. Continuing to go through iterative reviews of drilling and fracturing operations set the stage for continued improvement and larger successes. As with all projects of this nature, vast amounts of data are collected through every facet of the operation; something that nearly every operator struggles with is efficiently processing and analyzing the data so that conclusions and recommendations can be produced from them. This is often difficult within a single company, much less between two different ones. For this reason, the team arranged to have regular meetings in which both drilling and completions personnel were present. These meetings provided the team with the opportunity to discuss the data and findings at hand, as well as requirements moving forward. This collaborative environment ensured that redundant work was not being performed and also reinforced group cohesion.

On the drilling side, key indicators on each well, such as bit and mud performance, were scrutinized to ensure optimal operation and continued improvement. Looking forward, the drilling group also wanted to optimize the use of pilot holes. While being crucial in exploratory horizontals, pilot wells can often become costly and unnecessary as a project moves into development. By only employing them strategically, the team could ensure that data were acquired where needed without unnecessary rig time. One tool that was employed to aid in future developments of this kind was earth modeling software. The ever-expanding volumes of log data taken across the acreage were loaded into a main database where they could be processed and analyzed to build a three-dimensional (3D) model of the subsurface (Figure 2). Detailed cross-sections of specific areas could then be generated to aid in field development as well as specific wellbore planning. The addition of 3D seismic data later further refined the model.

Similar work was required for the equally large amount of data generated on the completions side. As the treatment design evolved, it became necessary to track how the changes affected the created fractures and their respective properties. Net pressure fracture modeling was used extensively for this analysis. Through this work, the team was able to obtain preliminary ideas of overall fracture length and height as well as proppant placement. This knowledge will be vital in well placement and spacing of future development wells.

Another notable enhancement to the design that was applied after the first well was to increase the proppant size. Post-job analysis indicated that because of the optimized transport capacity of the design, the smaller 40/70-mesh proppant could easily be switched to larger 30/50-mesh at the same amount with no added cost. When applied on the next treatment, the larger sand was easily carried with little if any adverse effects observed in treating pressure. The resulting proppant pack would be less susceptible to embedment and better able to facilitate higher production rates.

SUMMARY

This project realized an arguably higher degree of success than most other unconventional projects in the area. Whereas the majority of projects result in a normal distribution of exceptional wells and marginal ones, every well completed in the project was deemed economical. Several of the wells even had record-breaking initial potential tests for the area. As a whole, the project wells' six-month cumulative BOE production was 32% higher than comparable offsets (Figure 3). Although many important technologies were applied and used, the success is not attributable to any single one. The foundation of the accomplishment was the collaborative partnership between the operator and service provider, wherein a careful and diligent engineering workflow was used to repeatedly review previous work and attempt to improve future work.

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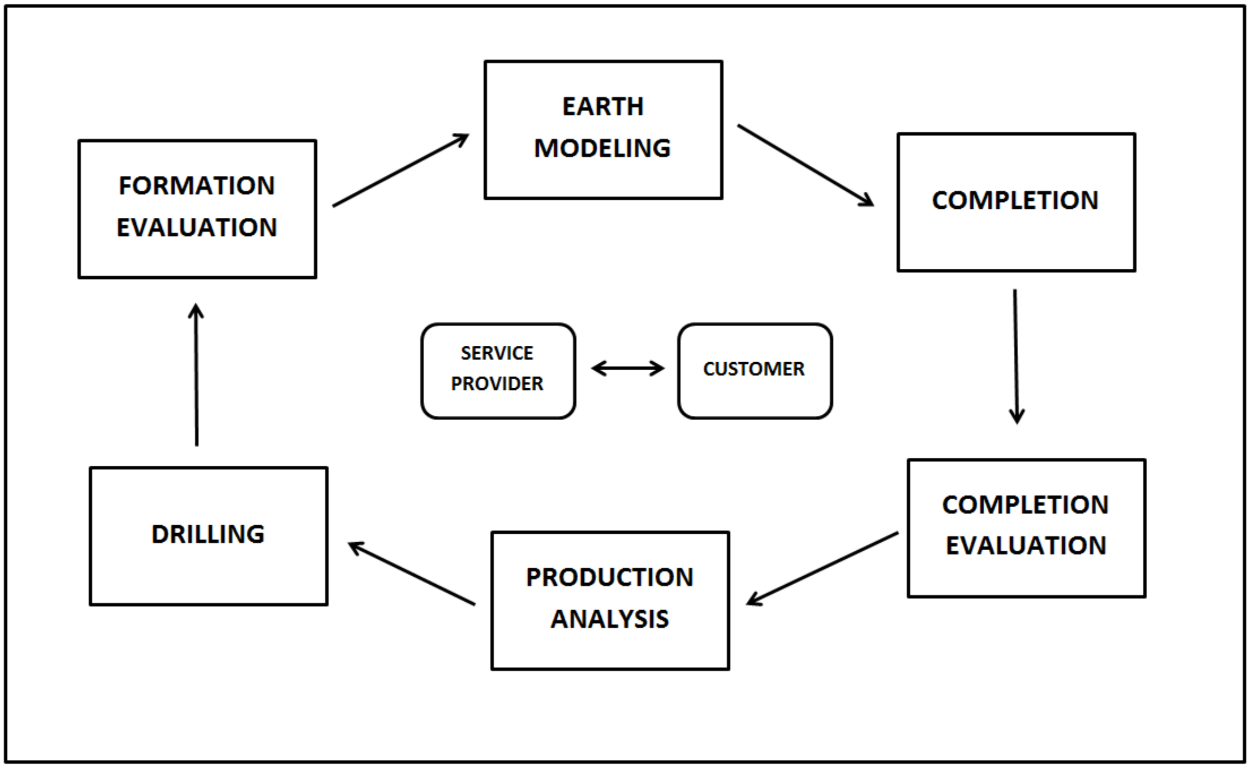

Figure 1 - Basic workflow outline.

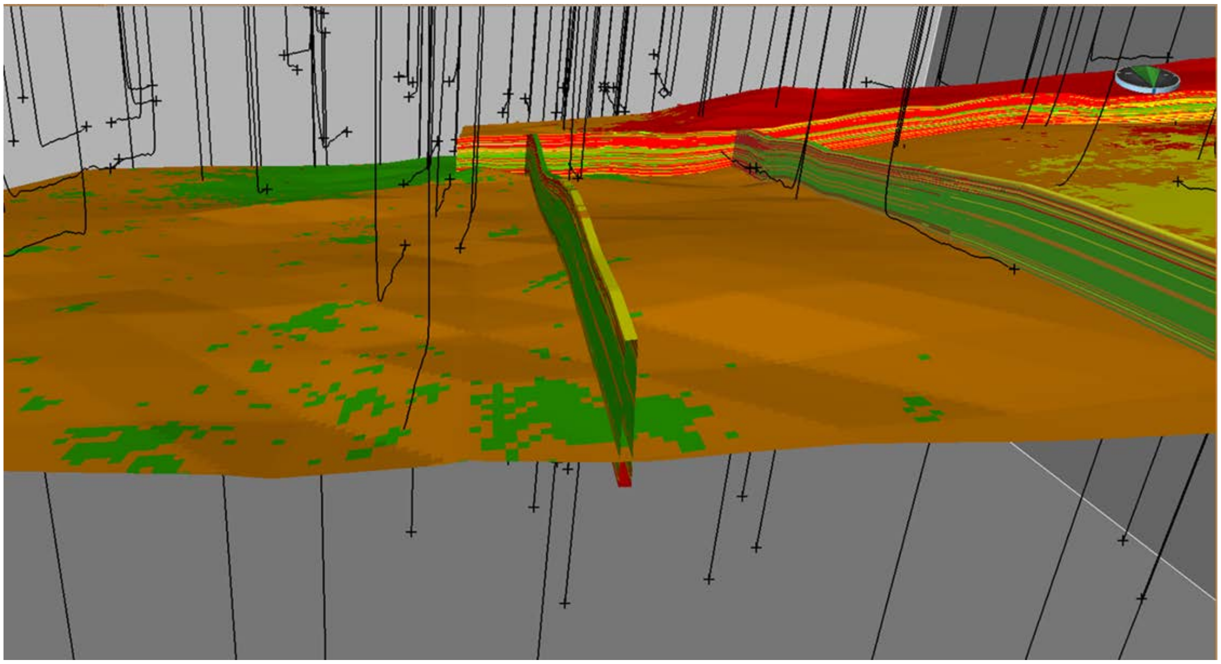

Figure 2 - Section of the subsurface earth model.

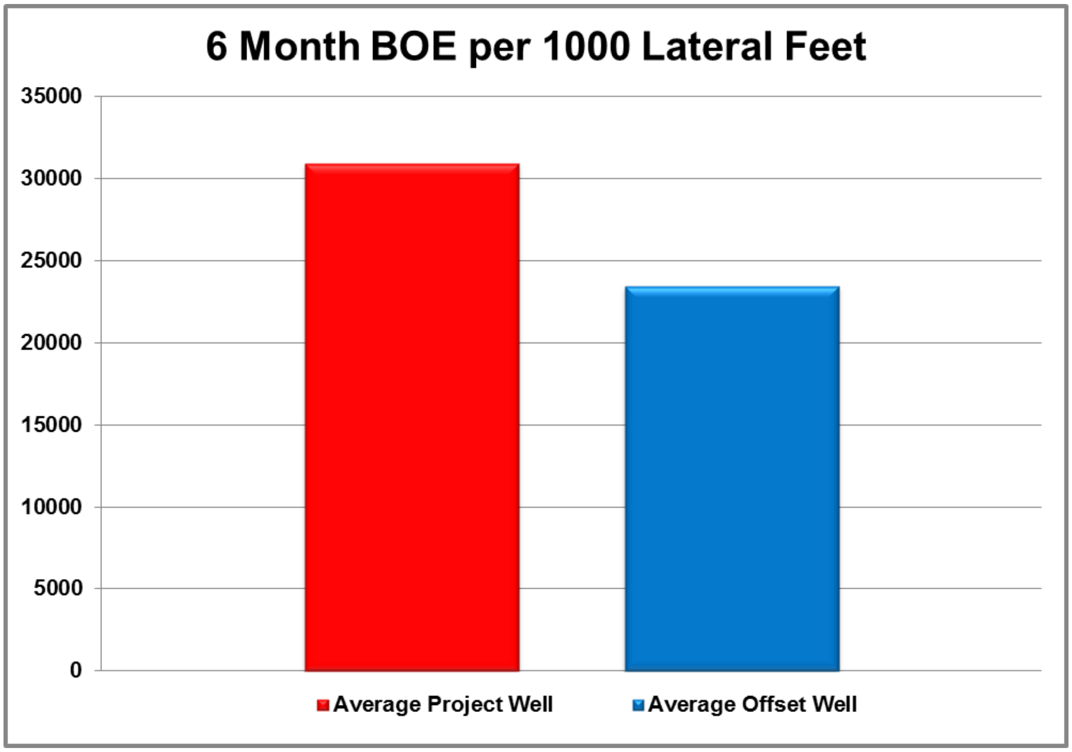

Figure 3 - Production comparison.