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A Case History of Comprehensive Hydraulic Fracturing Monitoring in the Cana Woodford

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Abstract

In the Cana Field in Western Oklahoma, horizontal wells are completed with multiple hydraulic fractures to economically produce from the Woodford Shale. This field development program is relatively young, and previous fracturing optimization had been achieved by trial and error testing. Cana wells usually are drilled with a 5,000-ft lateral, which is hydraulically fractured in 10-20 stages utilizing the plug-and-perf method with multiple clusters per stage. Throughout the early field development, there has been significant uncertainty regarding various subsurface parameters including: fracture propagation geometry, cluster contribution, and interference remediation. This paper describes a comprehensive fracture monitoring project, which will be used to further the understanding of the hydraulic fracture geometry, interference, deliverability, and production.

In late 2012, the project well was drilled as part of the infill development program. In January 2013, the well was completed with a 12 stage slickwater frac. Several established and cutting edge technologies were used to assist with monitoring the hydraulic fracturing operation of the subject and offset wells. These technologies included: Distributed Temperature Sensing (DTS), Distributed Acoustic Sensing (DAS), prototype cemented frac valves, permanent bottom hole pressure gauge, surface micro seismic, down hole micro seismic, offset bottom hole pressure monitoring, logging-while-drilling, advanced open hole logging, radioactive tracers, and chemical tracers. These technologies were used successfully to monitor cementing operations, offset fracturing, monitor well fracturing, coiled tubing drill-out, flowback, and initial production. This project has assisted in the understanding of subsurface events and is expected to provide continued insight into long term production. Similar projects are being considered for the future, and this technology may ultimately become part of the standard completion.

This paper will focus on the planning, logistics, installation, and operation of this one of a kind monitoring project in the Cana Field.

Introduction

The Cana Woodford is an unconventional shale gas play located in western Oklahoma, with the first horizontal well being drilled in 2007. Full field development is now underway utilizing the two key technologies (horizontal drilling and hydraulic fracturing) which have been successful in the economic development of other shale gas plays. True vertical depths (TVD's) range from 12,000-ft to 14,500-ft and lateral lengths vary from 4,500-ft to 5,000-ft. These depths create unique challenges for design and implementation of the hydraulic fracturing program (Wood, 2011). Early exploration wells and delineation wells were often affected by high treating pressures and the inability to consistently place designed proppant volumes. To successfully develop this play, improvements to the hydraulic fracturing process were necessary. Through trial and error testing, methodologies were developed for more consistent placement of the designed stimulation treatments. Once this consistency was achieved, it opened the door for design changes aimed at improving well performance and recoveries.

Field development in Cana is based on individual sections, with each section encompassing one square mile. Initial field delineation was achieved by drilling one "parent" well per section, which in turn identified a "core" area of the field. This core area is now being developed by drilling an additional eight wells per section. Development is being achieved by drilling 2-3 wells per single location (pad) utilizing 12-16 drilling rigs and two full time frac crews. Wells are completed sequentially moving east or west along a particular row. This allows for efficiencies in scheduling and logistics, as well as minimizing the interference between parent and development wells. The base completion design is a plug and perf completion consisting of ten stages configured with four perforation clusters per stage. Stage volumes consist of ~15,000 bbls of slickwater and 350,000 lbs 40/70 white sand.

Problem Description

Although the fracture placement issues previously described have been overcome (Wood, 2011), there are still many unanswered questions regarding completion parameters and production efficiency. During the exploration/delineation period, attempts were made to methodically adjust the design of the hydraulic fracture treatment by isolating a given parameter and determining the overall impact to well performance. Some of the tested variables included number of stages, fluid volume, proppant volume, and number of clusters per stage. Although this testing provided some insight into the optimum stimulation design, variations in geologic characteristics and reservoir quality prevented any definitive conclusions. Additionally, while technologies such as down-hole micro-seismic, chemical/radioactive tracers and production logs had been implemented with varying degrees of success, their use was somewhat sporadic and the results could not be adequately correlated.

With the commencement of infill development within the core, however, there now existed a unique opportunity to test individual variables within a more controlled and consistent setting. A "variable testing" program was designed which would allow for a specific variable to be tested within each section. By pumping a "base design" on four of the new wells within a section, the remaining four wells could be completed with a modified design. Comparing the performance between the base and modified designs would theoretically provide additional insight into which variable(s) had the most significant impact on production. During the planning stages of this variable testing program, it soon became apparent that the biggest drawback would be the length of time required to adequately evaluate the impact of each variable. Even with two frac crews running full time, it took months to complete the testing program and obtain any meaningful production results. It also became evident that even though this testing program might provide insight on which design parameters may ultimately affect production, it would not indicate how or why that impact was achieved. To fully optimize completion techniques within the field, a more thorough understanding of the stimulation process was necessary. Fiber optics (and other complimenting technologies) was subsequently identified as a means to gather significant and meaningful information in a relatively short period of time.

Scope and Objectives

The project scope involved the comprehensive use of various technologies in nine wells in a one square mile section. The primary well included a fiber optic installation utilizing both Distributed Temperature Sensing (DTS) and Distributed Acoustic Sensing (DAS). Project objectives focused on three distinct regimes:

- **Fracture stimulation monitoring.** Install and use measurement technologies with would improve the understanding of fracture propagation and geometry. For example, these technologies would help answer questions like: In a multi-cluster plug and perf scenario, where do the fracture(s) initiate? Does cluster spacing affect the fluid/proppant distribution during the treatment? Do natural fractures play a role in fracture initiation and geometry, and how do fractures from offset wells interact?
- **Flowback behavior.** Install and use technologies to monitor the early production (flowback). These technologies will answer questions like: What is the correlation between fracture treatment and flowback quantities? Does the flowback contribution profile change over time?
- **Production monitoring.** Install and protect the installed DTS equipment for long term monitoring. Use this permanent temperature profile from DTS and a permanent bottom hole pressure gauge to provide a long term production log. These tools can help with questions like: Does the production profile change over time, and does it correlate to what was observed during the frac and during flowback? How do changing conditions (choke changes, line pressure changes, reservoir depletion) affect the overall profile? Can production issues be identified (and addressed) prior to significant impacts on performance?

This paper will describe the process by which the technologies were identified and evaluated, as well as the extensive planning that was required to safely and effectively install and operate a comprehensive system designed to meet these objectives.

Technology Selection

In 2009, an internal Devon group used fiber optic sensing to monitor an open hole horizontal well with multiple transverse fractures (MacPhail, 2012). Based on the success of this operation, it became obvious that these same measurements would be highly beneficial to understanding cluster efficiency when cemented horizontal wells are completed with multiple clusters per stage. The project team selected the primary project well, which would be spud late in 2012 as the best candidate for this multifaceted project. This well was the McCray 2-26H, and was the last of 8 wells to be completed in the McCray section.

As described earlier, the normal completion process in the Cana field is plug and perforations with multiple clusters. There was an obvious challenge to installing a fiber optic sensing line in a cemented horizontal wellbore and later perforating the casing. Due to the risk of perforating the fiber optic line the normal completion method needed to be altered. However, since this was a data gathering project, we wanted to closely imitate our "normal" completion method so that it could be evaluated. This imitation required that we have the well was cemented and fractured through multiple clusters per stage.

Over the course of several months, alternative completion techniques where evaluated. There was a perceived risk of inadvertently perforating the fiber line with oriented perforating, so the team decided to focus the evaluation on cemented sleeve systems. The team investigated options from many service companies. Two primary requirements were a 10,000-psi pressure rating and multi-valves opening. This evaluation resulted in a decision to perform a trial on two systems:

- Cemented, external casing gun system activated by ball drop seats
- Cemented, multi-cluster, ball drop sleeve system

The trial was arranged so that both systems would be installed in the bottom 3 stages (out of 10) in similar Cana wells. In these trial wells, fiber optics would not be installed and it was only a test of the completion system at Cana pressures and temperatures. The remaining 7 stages would be completed with the normal plug and perf method.

Several months before the comprehensive monitoring project started, the ball drop system was installed without any issues in the trial well. Immediately after installation, this well was hydraulically fractured with a slickwater treatment comparable in size to the planned McCray well. During the stimulation, pressure increases indicated that all valves operated as planned and the fracturing treatment proceeded without issues. In this trial well, fracturing break-down pressures for the cemented sleeve stages was equivalent to the plug and perf stages. Overall, this trial was a successful evaluation of the cemented multi-cluster sleeve system.

Due to issues with drilling the 2nd trial well, the external casing gun system trial was delayed until late in 2012. Because of this delay, the team decided to move forward with planning to use the cemented sleeve system for the fiber optic installation.

Complementing Technologies Selected

The objectives of the project required collecting information that assisted with the fiber optic analysis. Likewise, the team wanted to utilize known fracturing diagnostic tools to evaluate DAS/DTS fiber optic sensing accuracy. These additional technologies included:

- Microseismic
- Offset pressure monitoring for interference
- Proppant tracers
- Chemical tracers
- Openhole formation evaluation
- Production logs

Microseismic

Microseismic was planned from the beginning to be the best complimentary fracture diagnostic tool. The team geophysicist evaluated a large range of possible configurations and service providers who would result in the best results for the project objectives.

As a result of this evaluation, a two technology approach was selected. First, a downhole microseismic array would be installed in a neighboring new well. Second, surface microseismic arrays would be laid out over the McCray 2-26H well. By using these two technologies, the project team hoped to achieve a good fracture geometry analysis in all three dimensions (X, Y, and Z). Since the team did not have any direct experience with surface microseismic, this would also let us evaluate the data quality of surface microseismic compared to downhole microseismic.

The downhole microseismic acquisition would be installed deep in the vertical section of the neighboring well, which is located 600-ft west of the McCray 2-26H.

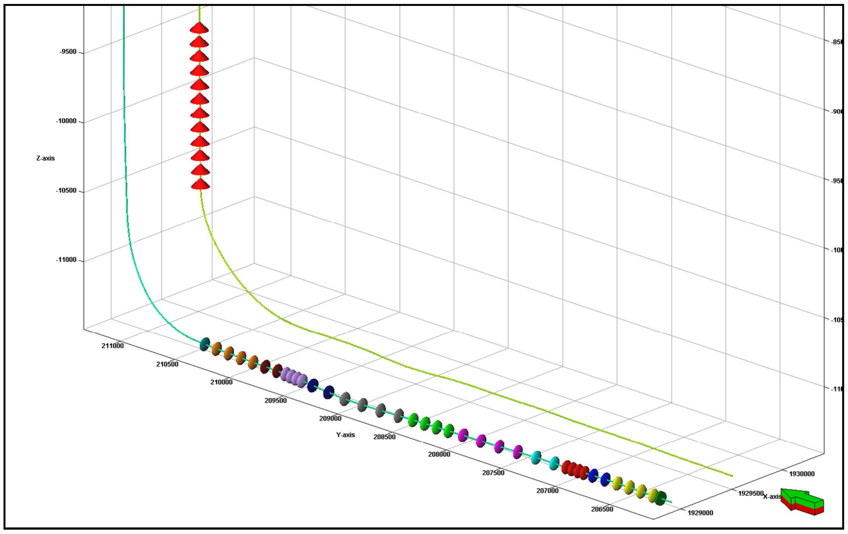

Fig. 1. Configuration of downhole geophones (red) in the monitor well and its relative position to the subject well.

The surface arrays would be laid out in a star pattern including 10 separate lines and a total of 1,476 stations spaced at 90-ft intervals. See figure 2. The McCray 2 well is shown in yellow and the surface microseismic lines are shown in red. This array pattern covered an area of 26 sq. miles.

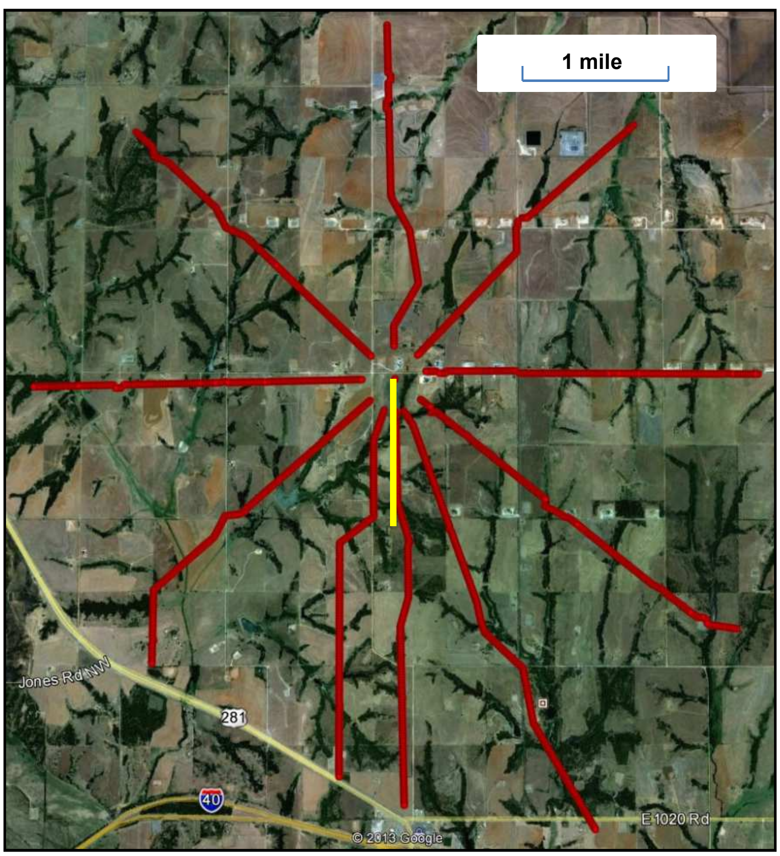

Fig. 2. Geographic map showing the planned layout of the surface microseismic geophone lines.

Offset Pressure Monitoring for Interference

Since fracture interference is common in the Cana Woodford field and since the McCray 2-26H had several close offset wells, the team decided to collect pressure data from multiple points during fracturing operations. This pressure data would later be analyzed to provide fracture azimuth, an understanding of complexity (or lack of complexity), and fracture conductivity. (Daneshy, 2012)

Proppant and Chemical Tracers

Chemical tracers and proppant tracers had been used previously in Cana and provided useful information in completion effectiveness. Based on this previous experience, the team wanted to further evaluate the accuracy of these diagnostic tools. Planned proppant tracers included iridium, antimony, and scandium. Chemical tracers would be collected during the flowback of all wells within 1 mile.

Open Hole Formation Evaluation

A key part of the project objectives was to understand the role of formation heterogeneity on hydraulic fracturing. This meant that data needed to be acquired about the heterogeneity of the formation. The team evaluated available options and how they could be used without jeopardizing drilling operations or the fiber installation. The team elected to collect standard triple-combo type open hole logs using Logging While Drilling (LWD) tools. After the well reached total depth, a single drill pipe conveyed logging operation would be performed, which included an ultrasonic borehole imager, azimuthal sonic tool, and an oil-based micro image tool.

Planning the Fiber Installation

Because a ball drop sleeve completion method was selected, the installation planning was significantly more complicated than the traditional Cana casing installation. An installation featuring any new technology can be difficult enough, but when several new technologies are combined, it is very easy to make mistakes. A minor mistake could result in lost rig time, but a major mistake could potentially cause complete project failure. As detailed above, an array of complementary technologies was planned and they all required that the fiber would be installed correctly and to full depth. Similar to the standard Cana Woodford design, the installation featured 5-1/2” production casing, using a “toe initiator sleeve” to facilitate quick and efficient fracturing operations without a tubing conveyed perforation (TCP). But, that is where the standard part of the installation ended.

As described earlier, a cemented multi-cluster sleeve system featuring 37 specifically spaced valves and a 10,000-psi burst rating was selected. The fiber must be installed on the outside of casing continuously from terminus to surface, so obviously, it must pass each valve along the way. This created concern for an upset with a high wear rate located right at the large valve OD that could potentially damage the line as it is being run in the hole. Also, being close to the ports themselves during treatment raised the requirement for improved fiber optic line protection. To combat both concerns, the valve design was modified to include a channel for the 11mm encapsulated fiber line in a 120º “blanked” positioned between the ports. However, to meet the burst design requirement the valve bodies would be enlarged radially to compensate for the reduction in wall thickness near the channel. See Figure 3. Including the toe initiator sleeve, the planned completion included were 38 valves, each approximately 4’ in length with a 7.6” OD. In the heel of the well, an eccentric 7.75” OD pressure gauge mandrel required its own ¼” stainless control line to surface.

Figure 3 – Picture of one (of 37) ball drop valve used in the project.

Nearly every Cana Woodford lateral drill string and production casing string has its running friction predicted and actual results analyzed afterwards. Using this historical data, it was obvious that the planned surface location would result in casing not reaching total depth. See Figure 4. The typical Cana surface pad features 2-3 wells with up to 1,300-ft of displacement required to line up the horizontals in their designated development slot. The McCray 2-26 was originally designed to be the 3rd well off the pad with 1000-ft of displacement and 200-ft of "negative vertical section" to maximize completed lateral length.

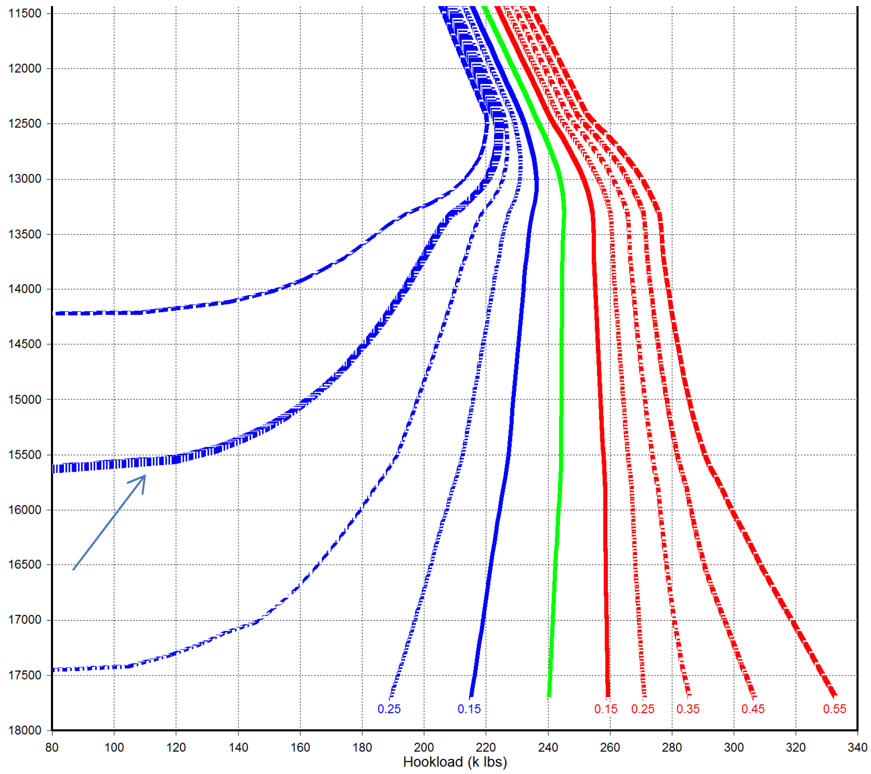

Figure 4 – Predicted drag forces if original surface hole was used.

Assuming the casing connection can tolerate the torsional load, it is a widely accepted technique to rotate casing to break axial friction. Unfortunately, this technique is impossible with the fiber and control lines in the wellbore. To eliminate this deal-breaker, the McCray 2-26H surface location was moved to an individual pad directly above the planned heel of the well. This surface location change eliminated excessive displacement, and therefore drag, that would have required rotation. See figure 5. Further utilizing the historical torque and drag data, a rotary steerable drilling BHA was selected over the conventional bent mud-motor and MWD combination. In Cana, some of the lowest realized production casing friction factors resulted from drilling with a rotary steerable system (RSS). This has been duplicated multiple times and while not normally necessary it was a very desirable attribute for the project. The other benefits of the RSS are integrating LWD logs into the drilling BHA, eliminating one drillpipe conveyed logging run at TD, and continuous rotation while drilling which will increase ROP and potentially improve hole cleaning.

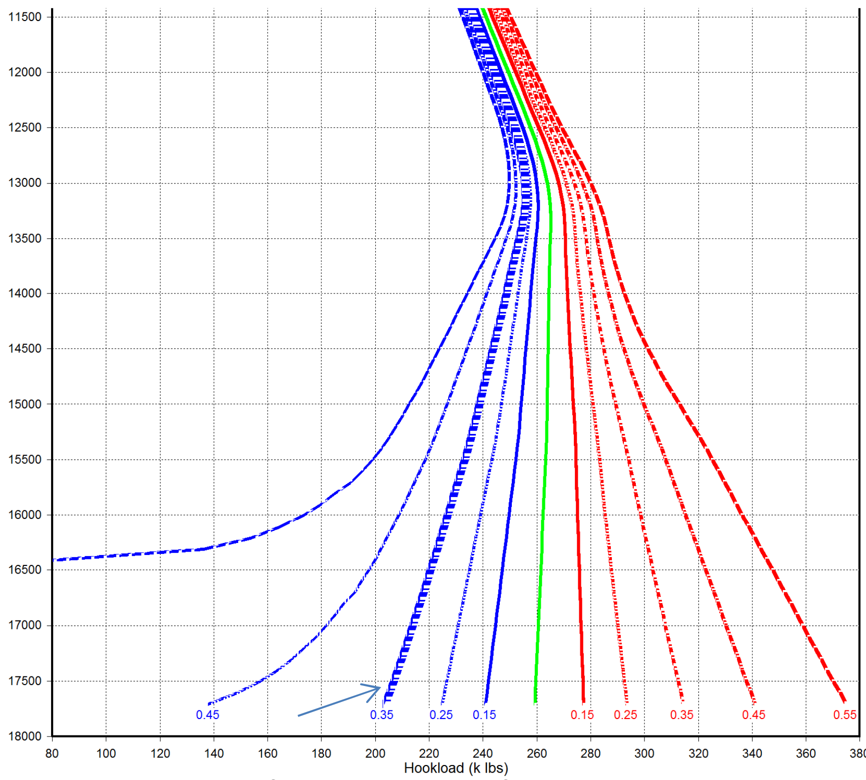

Fig. 5. Predicted drag forces with revised surface hole location.

In many situations, what is considered an acceptably clean hole to drill ahead, trip a BHA without a stuck pipe incident, and run casing to total depth, can vary dramatically when larger than normal completion tools or stabilizers with reduced junk slot area are integrated into the design. Tolerated residual cuttings load is relative and will likely have to be reduced before attempting an installation of this type. Backreaming of drilling BHAs can carry a negative connotation, but many times that is the result of poorly executed unplanned backreaming implemented as a response to poor hole conditions. Backreaming may increase risk in some aspects, but it can also produce the cleanest possible wellbore and as such it was integrated successfully into the clean-up protocols. Backreaming from TD with the highly stabilized RSS and LWD BHA proved to be one of the most challenging aspects of the entire procedure.

While rotary steerable systems, backreaming, and other enhanced clean-up techniques can produce a relatively clean wellbore, it is virtually impossible to completely remove all debris, especially a one mile horizontal wellbore. That being the case, stabilizer and centralizer design was not overlooked. The directional company and drilling engineer worked together to select and model stabilizers that had sufficient standoff and junk slot area but also had a minimum amount of spiral wrap. Excessive spiral wrap, especially when combined with small junk slot area, can add significant risk when attempting to pass thru any appreciable amount of cuttings. This consideration was also used for centralizer selection. Previous centralizer modeling suggested that 65-85% standoff was achievable using a relatively tight centralizer spacing regime thru the lateral and curve. Tight centralizer spacing has historically been used to improve cement quality, but in this application, it also decreases the likelihood of fiber cable wear. A straight blade centralizer with a large junk slot design also increases the ability to move thru residual cuttings beds instead of acting to plow them ahead. The final design criterion was that the centralizers could not be allowed to move or rotate independently of the string. Consequently, the selected centralizers had 10 total blind set screws to keep them from spinning on the casing. Shop testing suggested that at least 8,000ft-lbs of torque was necessary to spin the centralizer when properly installed. In the vertical portion of the wellbore, centralizers were not necessary and instead a “cross coupling clamp” would be used to protect the cables and hold the lines to the casing. The centralizers and cross coupling clamps are shown in figure 6.

Figure 6 – Centralizers and cross coupling clamps are stacked on the rig floor.

Valve Test

One of the few aspects of the entire installation that could be tested independently and economically in a separate wellbore was the cemented, ball drop sleeve system. As mentioned earlier, a trial well was identified and a 12 valve test was successfully executed. This allowed drilling and completions to become familiar with the system and test its operation. These trial valves were not identical to the increased OD version with the fiber channel, but still gave a very good data point. The final drag analysis for this trial well installation showed very little deviation from what would be expected from a casing string without valves. See figure 7.

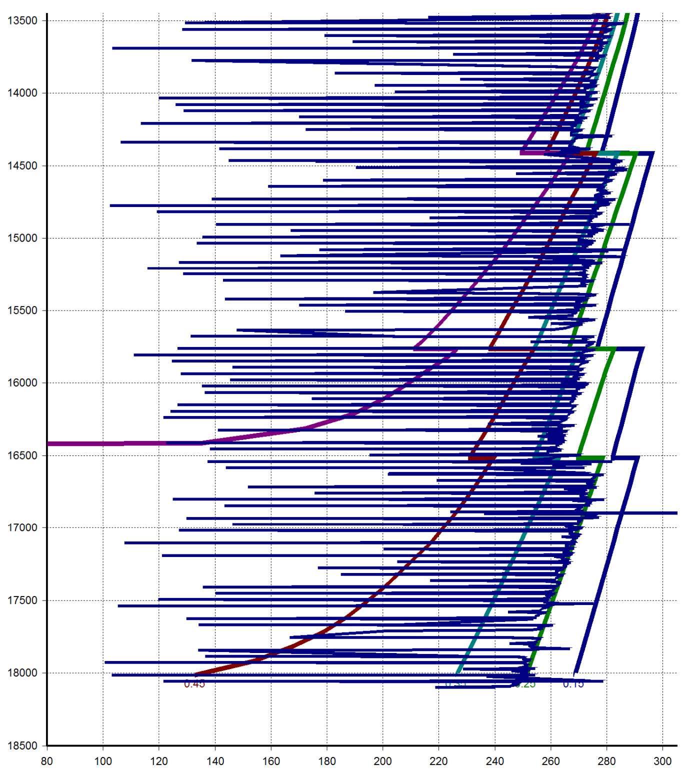

Fig. 7. Graph of the actual and modeled drag forces during 12 valve installation in the trial well.

Walk Thru

A complete "dry" walk thru of all the systems proved invaluable. Representatives from each service company involved with completion installation met in Oklahoma City months ahead of the scheduled installation. This gave an open forum for all the companies' office and field personnel to discuss, raise concerns, and ultimately find solutions to potential problems. A single ball drop valve, fiber cables, centralizers, casing, and the pressure gauge carrier were assembled at the casing crew's facility. Once the team was able to see and feel the downhole components, the best surface handling equipment was selected. The team was also able to build a list of action items and to document what equipment would be delivered to the wellsite.

Figure 8 – Field and office project members participate in "walk thru" at casing company's facility.

From there, the group traveled to the wellhead provider's facility and performed a full stack up of the wellhead equipment. The standard Cana wellhead required modification to accept the fiber and control lines. Setting the slips, installing the packoff, and terminating the lines were all rehearsed and multiple small issues were identified and remediated. See figure 9. Finally, the group traveled to the drilling rig to inspect actual conditions at the wellsite. An existing, completed surface installation was also visited to identify any potential surface installation issues.

Fig. 9. Drilling Superintendent inspects the modified wellhead during the dry stack up of wellhead components at service company's facility.

Another shop test and walk through found a deficiency involving the backup plan in case the valve system failed or if the seats had to be drilled out prior to completing all stages. While it had been assumed that two braided wire cables installed along either side of the fiber optic line could be located if oriented perforating became necessary, shop testing indicated logging tools were not capable of detecting the cable. Steel rods were then welded inside the cable clamps, and subsequent testing indicated they should be detectable if needed.

Because of all the upfront design work and coordination, actual installation was destined to be successful with minimal errors.

Installation

Custom length 5-1/2" LTC casing was loaded on the racks in pre-tallied running order. This required additional up-front work, but simplified casing running operations. Cluster spacing was one of the main variables to be evaluated, so valve spacing was critical. Custom length casing was a better solution than juggling inventory pipe, which is fairly uniform in its length. Consistent casing length is normally a desirable trait but in this case it would not allow for the precise placement of the valves without multiple pup joints. However, while widely varying casing lengths may achieve specific valve spacing, it does not lend itself to easy handling by a conventional casing crew with a "stabber" in the derrick. The ultimate solution was a casing running tool (CRT). The CRT eliminated the stabber in the derrick, the platforms around the rotary table that obstruct line of sight, and the conventional power tongs that have much greater potential for damaging the lines. A picture of the CRT is shown if figure 10.

Fig. 10. The CRT is hanging above the rotary table.

All valves, centralizers, and lines were run without incident. The fiber line was ran continuously from the shoe track to surface, but a wear-arresting, sacrificial pair of ½" braided steel lines sandwiched the fiber line in the distance between each valve. This configuration is shown in figure 11. Above top of cement, the operation was much simpler as a hydraulically installed "cross coupling clamp" was used to both protect and secure the lines. These are shown in figures 12 and 13. Using cross coupling clamps did not slow down casing installation much more than conventional casing installation. The casing was cemented in place at total depth without incident. Cementing pressures were consistent with upfront modeling and showed no increase from the large valve diameters. The final drag analysis showed very little difference from what would be expected from a string without fiber and valves. This drag analysis is shown in figure 14. .

Fig. 10.The fiber line is banded to casing along with ½" inch braided steel cables paralleling on each side. The blue centralizer is locked in place beneath the casing coupling.

Fig. 11. Service company personnel install a cross coupling clamp.

Fig. 12. A cross coupling clamp holds the yellow fiber optic line and the BHP gauge line to the 5-1/2" casing.

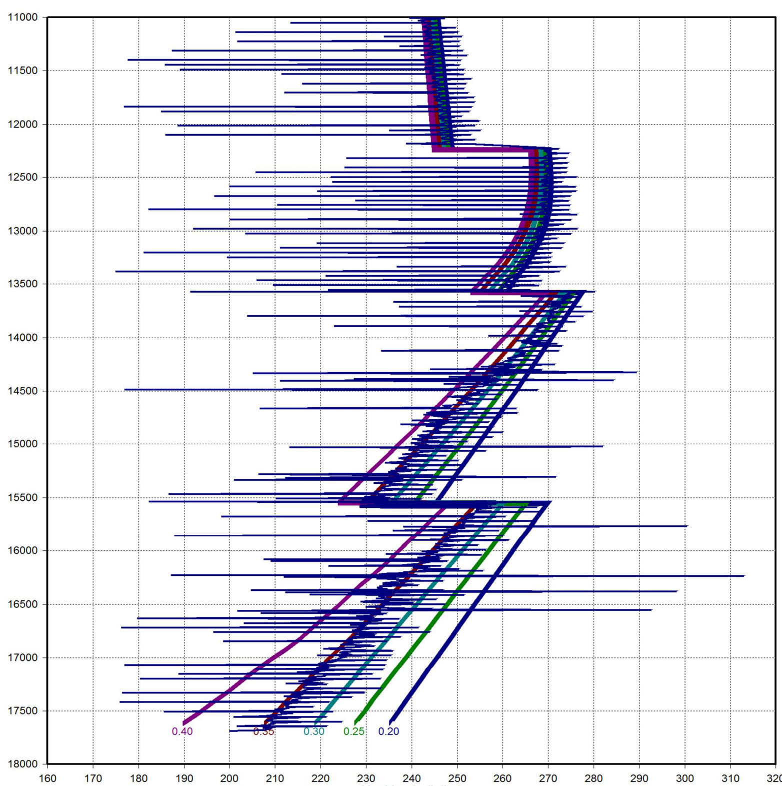

Fig. 13. This drag analysis chart shows the actual and modeled drag forces during installation with casing fill-ups included.

Completion Operations

Soon after rig installation operations were finished, completions operations began. The wells were completed from east to west, and the final well completed was the fiber optic equipped McCray 2-26H. Figure 14 shows various unique operations related to the project.

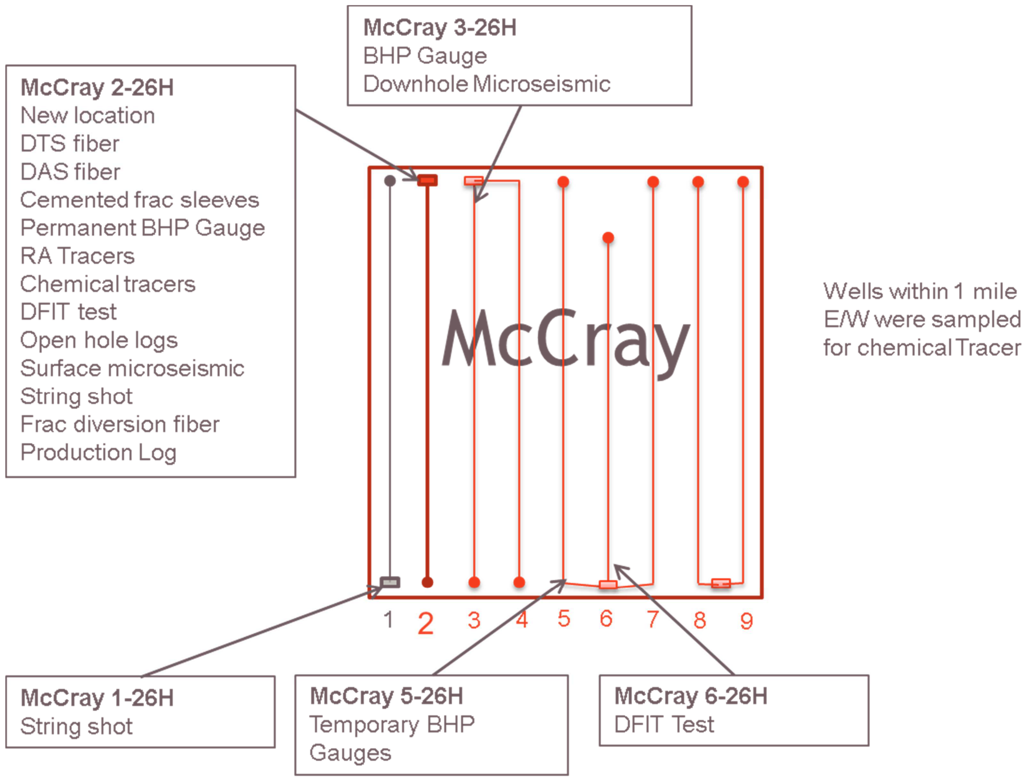

Fig. 14. Overview of unique aspects of project

In late December 2012, Diagnostic Fluid Injection Tests (DFIT) were performed on the McCray 6-26H and the McCray 2-26H. The McCray 2-26H DFIT was performed by opening the toe initiator sleeve near the end of the well and injecting approximately 20 bbls at 5 bpm. The McCray 6-26H DFIT was performed by pumping a similar volume into one set of perforations located near the toe of the well.

In early January 2013, hydraulic fracturing operations began on the McCray 4-26H and McCray 3-26H wellsite. The McCray 4-26H was first, with the McCray 3-26H immediately following. These wells were stimulated using large volumes of treated slickwater. Both wells were fractured in 10 stages along the horizontal wellbore, and each stage used four perforation clusters per stage. During these fracturing operations, DTS and DAS data was monitored and acquired from the McCray 2-26H wellbore. Likewise, bottom hole pressure data was acquired from the McCray 2-26H, which still had communication to the formation through the toe initiator sleeve. These measurements were collected to better understand fracture geometry when it was 600’ and 1,200’ from the treating well.

Several days later, the surface microseismic vendor began to lay out the array lines in a star pattern. This star patterned array included 10 lines, which had a total of 1,476 geophone stations. Each of these stations was spaced at 90’ and each was buried underground a few inches. The star covered approximately 26 sq. mi and was approximately 5 miles wide. This installation took several days and was completed in adverse winter conditions. Because the temperature was below freezing, picks and shovels were required to bury many stations. Later, quality control inspections found many of the arrays were still above ground, and last minute re-installation needed to be done the day before data acquisition began.

On January 17th, bottom hole pressure (BHP) gauges were installed in the McCray 5-26H wellbore. The composite bridge plugs (CBP) in this well had been drilled out during the previous two days. The BHP gauges were ran under a retrievable production packer and deployed with electric wireline.

Later that day, BHP gauges were installed on the McCray 3-26H. This well did not have CBP’s drilled out yet, but these CBP’s were ball-drop, flow-through type. Consequently, full pressure communication with the wellbore was expected. These BHP gauges were also installed under a retrievable production packer. This well was also the “monitoring well” for downhole microseismic. Downhole microseismic monitor wells need to be open at surface during deployment. This requirement meant that another barrier needed to be installed downhole. Consequently, a retrievable bridge plug was ran on e-line and tested after the packer was installed.

On January 18th, the downhole microseismic array was deployed in the McCray 3-26H. Immediately after this deployment, Vertical Seismic Profile (VSP) was acquired. This zero-offset ZSP utilized a vibrator truck located near the edge of the McCray 3-26H wellsite. Ultimately, this array remained deep in the vertical section of the wellbore, with the bridge plug and packer directly below the array tools.

After the VSP data had been acquired, multiple string shots were performed. These string shots were needed because the subject well would not be perforated. The first of these string shots, which utilized 80' of explosive primer cord, was conducted in the heel of the McCray 1-26H. This string shot was attempted twice, but the signal was too weak during both attempts to be utilized by downhole microseismic, which was located in the McCray 3-26H vertical, approximately 1 mile north. A third string shot was performed in the heel of the subject well, McCray 2-26H, later that night. The signal in this attempt was sufficient to help calibrate the velocity profiles for both surface and downhole microseismic companies.

The following day, fracturing operations began on the McCray 2-26H. This well was fractured in 12 stages, with various cluster (valve) spacing and configurations. Fracturing was monitored real time with the BHP gauge, DTS, DAS, and surface microseismic. During the fracturing operations, the three proppant tracers (Sc, Ir, Sb) were alternated into each stage. Likewise, individual chemical tracers were included in each stage.

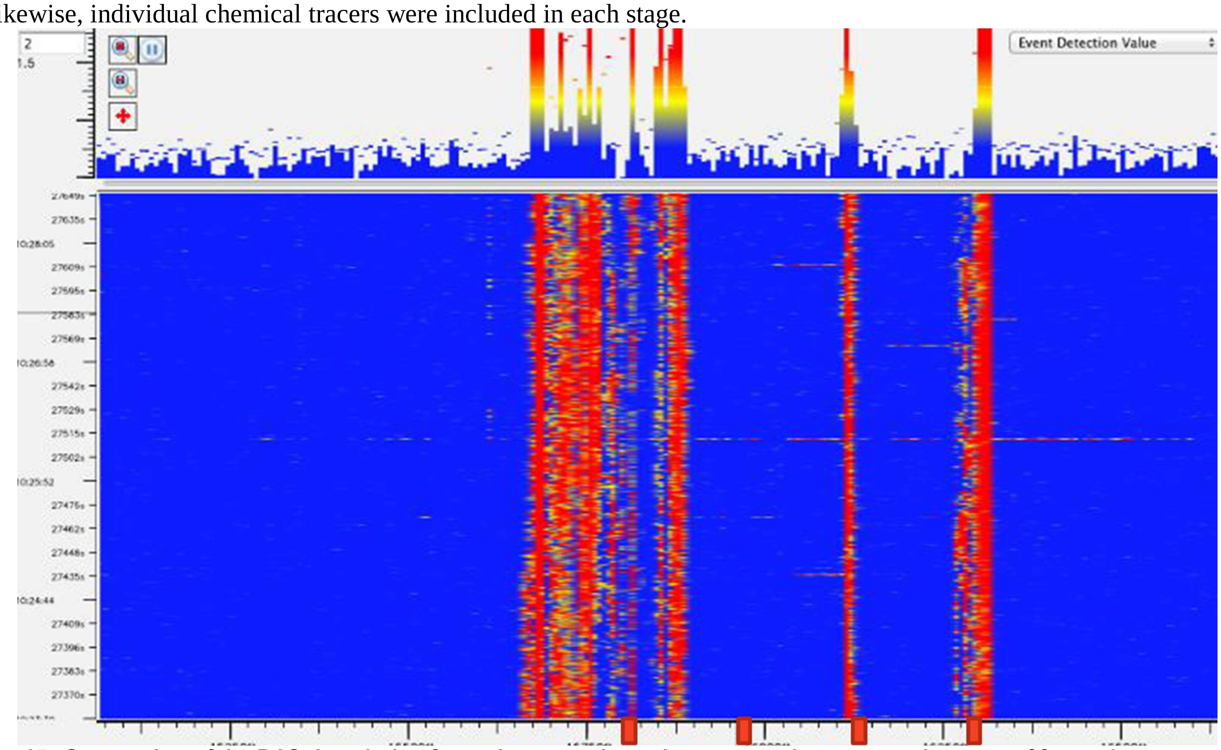

Fig. 15. Screen shot of the DAS data during fracturing operations shows acoustic energy at three out of four valves.

Handling the data generated from the DAS acquisition unit was challenging after the job finished. The acoustic (DAS) data alone exceeded 30 terabytes, and there are currently only a handful of people in the industry capable of handling and processing this kind of information. Hard drives had to be physically moved to the appropriate people rather than being transferred electronically, and a computer had to be specifically built to import and process the data.

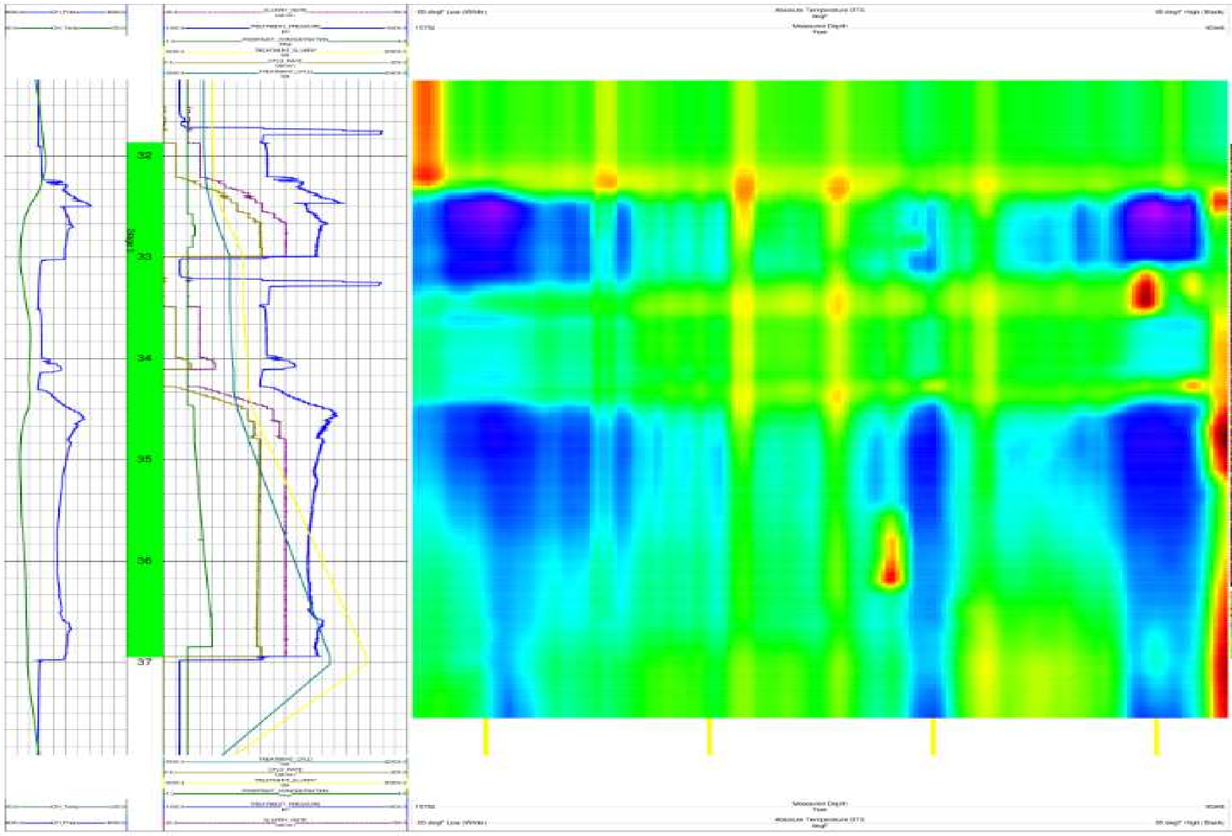

Fig. 16. Visualization of the DTS data during fracturing operations.

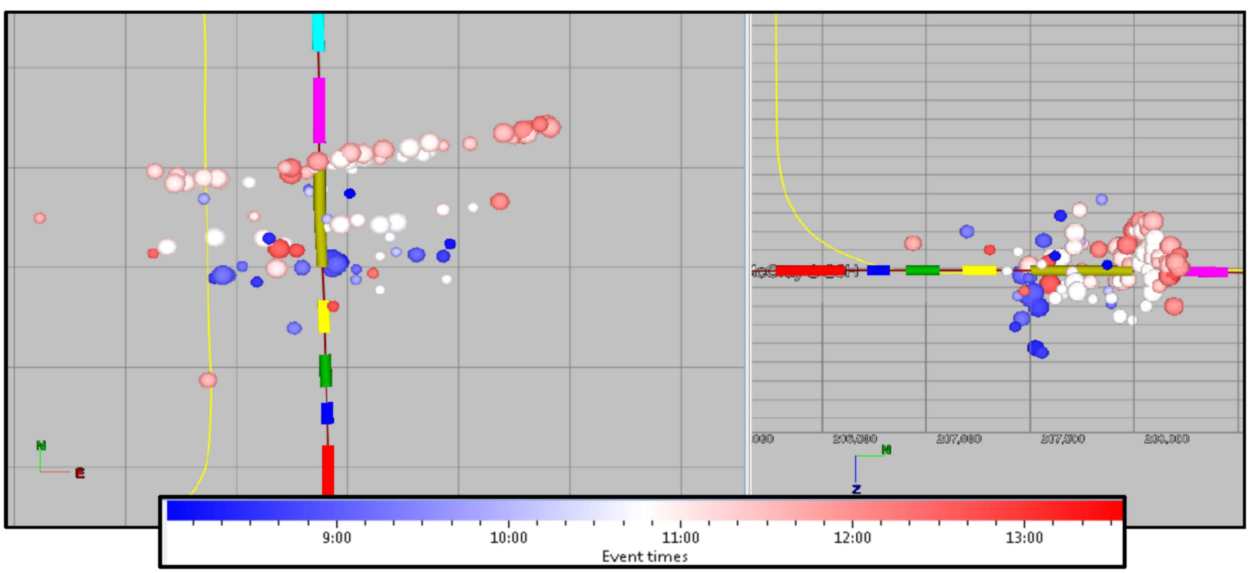

Fig. 17. Visualization of the microseismic data during fracturing operations.

Following the fracturing stimulation operations, a coiled tubing unit was mobilized to the wellsite to drill out the balls and valve seats. There was substantial milling issues with the ball seats and this operation lasted 5 days.

When coiled tubing operations were finished, the well began to flow through flowback test equipment. Throughout these steps, DAS, DTS and BHP were acquired for post job analysis. After the well began stabilized gas production, the DAS acquisition was terminated and the corresponding acquisition equipment was demobilized from location. The DTS and BHP acquisition units were permanently installed at location to provide permanent monitoring on the well.

Conclusions

As described above, this project involved significant planning and attention to detail. One of the most critical takeaways, therefore, was that ***early planning*** was essential to the success of the project. Looking back, there were very few (significant) problems encountered during the installation and implementation of this comprehensive monitoring system. That being said, there were numerous ***opportunities*** for problems or failures. Although there were many important steps to the planning process, the most important "lesson learned" was that a ***fully integrated*** project team, formed early in the project life, was absolutely critical to the overall success of the project. In addition to involving all necessary disciplines (Completions, Drilling, Reservoir, Geology and Geophysics), it was essential that each team member fully bought into the project and took ownership of their individual responsibilities. To that end, each discipline needed to understand not only what the other disciplines were doing, but why they were doing it. If Drilling didn't understand ***why*** Completions wanted to run fiber optics or sleeves, then it would be easy to come up with reasons why it couldn't be done. If Completions didn't understand why Geophysics wanted both surface and down hole micro seismic data, then it would have been reasonable to develop excuses for why it was impractical. There were numerous opportunities along the way for one particular discipline to forego or eliminate a step to make their job easier, but with a complete understanding of the project objectives, the team continually looked for solutions rather than excuses.

As previously described, one of the most obvious and often overlooked steps in a complicated projects is a pre-job "walk thru" of all system components. One of the most invaluable exercises during the planning and design process was a "stack up" of many of the system components. Representatives from each engineering discipline, as well as field supervisors, foreman and service company representatives met and walked thru all aspects of the proposed installation. Several critical deficiencies became evident during this process, any one of which could have resulted in significant delays if they had not been identified and resolved prior to the actual installation.

Overall, this project was a tremendous success from both an operational and engineering standpoint. It has been shown that numerous technologies, new and traditional, can be combined into a comprehensive monitoring project to provide valuable insight to both completion and production issues. Fiber optic sensing (temperature and acoustic) is an excellent means for monitoring real time downhole fluid flow through individual perforation clusters during frac treatments. Surface microseismic provides meaningful real time information regarding fracture geometry and complexity. Offset bottom hole pressure data, when appropriately collected and analyzed, can provide indications of fracture azimuth, fracture length, and indications of complexity. Radioactive tracers, chemical tracers, production logs and downhole micro-seismic are all useful and provide insightful information when used in conjunction with other technologies.

Through additional and continued analysis of the information collected (and still being collected) from this comprehensive monitoring project, it is anticipated that future similar installations can be used for fracture monitoring to affect real time decisions and improve overall efficiencies. For that to become a reality, there are certainly challenges that need to be overcome. Data integration and data management are significant hurdles. Ultimately, though, it is hoped that this type of monitoring can be used to improve the stimulation process through real time monitoring. Decisions such as decreasing or extending stage volumes, applying diverter techniques or adjusting perforating schemes could potentially improve performance and/or decrease costs. Future installations are currently being planned, and a multi-well fiber optics project using plug and oriented perforating technique is slated for installation later this year. As this technology continues to develop, its usefulness will be better understood.

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