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Advanced cuttings analysis provides improved completion design, efficiency and well production

Guy Oliver[1*], Graham Spence[1], April Davis[1], Sergey Stolyarov[2], David Gadzhimirzaev[2], Benjamin Ackley[3] and Casey Lipp[3] highlight how the application of an optimized hydraulic fracture stimulation plan, by honouring lateral well geological heterogeneities, improved completion efficiency and well production within the Cleveland Sandstone formation, Oklahoma, USA.

Recent case studies of lateral well completions have highlighted the apparent ineffectiveness of geometric stage performance with regards to fracture initiation and stimulated reservoir volume (Far et al., 2015; Ashton et al., 2013; Ganguly and Cipolla, 2012). It has been observed that poor stage performance can be attributed to varying rock type compositions along the borehole, due to lateral facies changes and/or wellbore porpoising. The inefficiencies linked to non or poor performing stages can result in higher costs, associated with equipment and materials, and limit the production potential of wells.

This case study highlights how the application of an optimized hydraulic fracture stimulation plan, by honouring lateral well geological heterogeneities, improved completion efficiency and well production within the Cleveland Sandstone formation, Oklahoma, USA.

Optimized completions

Designing optimized hydraulic fracture stimulation in a lateral well requires an understanding of the near-well bore geomechanical properties and the near-well bore and far-field stresses along the entire lateral. Such reservoir characterization is normally developed from geomechanical and petrophysical analyses using wireline or logging-while-drilling (LWD) services that include acoustic and borehole-image logs. Unfortunately, economic considerations can often inhibit or prohibit the use of logging techniques and hence the complete characterization of the reservoir, especially in the current low oil and gas price environment.

A practical and convenient alternative for reservoir characterization is to use the commonly available cuttings samples to provide gross characterization of a vertical or lateral well. Utilizing Automated Mineralogy (AM) techniques, such as CGG's RoqSCAN™, (Ashton et al., 2013)

provides comprehensive data from these cuttings which includes mineralogy, texture and rock properties throughout the entire length of the well. RoqSCAN analysis can be performed either in the laboratory or at the well site to provide near-real-time reservoir navigation and data to optimize the design of completions that will be performed soon after the well reaches total depth (TD).

Case study: Cleveland Sandstone Formation

Located in the Anadarko Basin, Oklahoma, the Cleveland Sandstone formation is 100-300 ft thick and composed of low-permeability sands (ranging from 0.001-1.1mD) deposited within a succession of highstand deltaic and low-stand incised-valley-fill deposits. The sequence-stratigraphic and depositional settings of these reservoir sandstones are complex (Hentz and Ambrose, 2011) which can lead to vertical and lateral compartmentalization of the pay zone along the length of the lateral. First gas was produced from the Cleveland Sandstone in the 1950s and data from 2012 indicated total gas production in excess of 4.1 TCF and 530 MMBO (Mitchell, 2012; Hentz and Ambrose, 2011).

In these sedimentologically complex environments, rock properties at the borehole can vary significantly along the length of the lateral well. From experience, it is important to identify the intervals of heterogeneity where rock type varies, with regards to stage and perforation placement. It has been demonstrated (Ashton et al., 2013) that keeping stages within similar-type rock ensures efficient stimulation and maximum stage performance.

Study area and objectives

Two lateral wells, Well A and Well B, were drilled into the Cleveland Sandstone in Ellis County as part of a four-well pad development. Peregrine Petroleum commissioned Baker

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Figure 1 Location of Ellis County, Oklahoma.

Figure 2 RoqSCAN system on location at well site.

Hughes to provide an integrated solution which included testing the effectiveness of the RoqSCAN reservoir evaluation service on a 'Plug and Perf' hydraulic fracture (frac) campaign. Wells A and B displayed similar rock properties, so frac optimization based on RoqSCAN cuttings analysis

was utilized for Well A, while Well B was completed as a standard geometric completion.

RoqSCAN advanced cuttings analysis

RoqSCAN (Figure 2) is a surface logging tool that delivers accurate, quantitative compositional and textural mineralogical data from drill cuttings or core pieces using a non-destructive Scanning Electron Microscope (SEM) and Energy Dispersive Spectroscopy (EDS) portable and ruggedized platform. It has given operators the ability to access near real-time mineralogical and textural information to better understand key rock texture and compositional parameters such as pore size distribution, pore aspect ratio, rock chemistry, mineralogy and lithotype. The information provides an independent geological assessment which complements other logging techniques to aid understanding of rock properties which can then be used to better constrain the completion model by honouring the mineralogical changes along the borehole.

The mineralogical data for Well A is summarized in Figure 3, plotted against measured depth and the borehole trajectory. One hundred and four cuttings samples were collected at 50 ft spacing and then prepared and analyzed at the wellsite.

The measured mineralogical data is used to define Rock Types which incorporate compositional mineralogy, brittleness index (BI) and textural data (Table 1). The Rock Type scheme is presented towards the right-hand side of the RoqSCAN summary chart (Figure 3). The scheme is a

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continuum scale moving from a more ductile BI with a pore system dominated by smaller pores, to a more brittle BI with a pore system dominated by larger pores. The scheme, together with BI, is a key input into the Completion Model which is further discussed below.

When dealing with cuttings data, it is important to determine if the cuttings are on depth. The mineralogical data (including the RoqSCAN GR curve) was compared to the MWD Gamma Ray and drilling data and was shifted appropriately in order for the measured mineralogical data to depth-match the log-derived data.

Based on the mineralogical and textural components, the well was divided into three gross lithological sections (Figure 3).

Section A (9480 ft MD-10,600 ft MD) represents the basal part of the pay zone, and is characterized predominately by quartz (avg. 41.41%) and mixed clay (avg. 27.31%) with a dominantly sub-rounded to sub-elongate pore system probably associated with micro-laminations.

Section A is a zone of relatively high brittleness and has been interpreted as dominantly rock type K with intermittent J and L rock types.
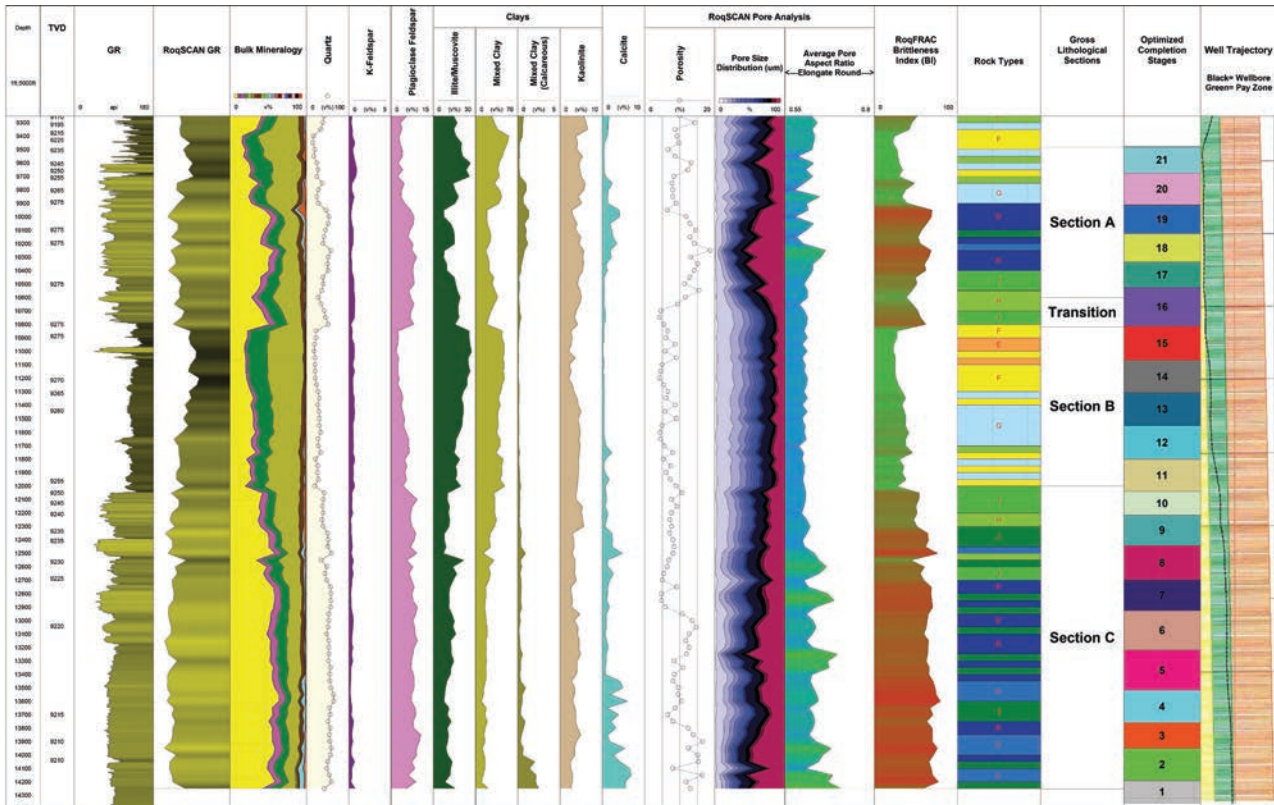

Figure 3 RoqSCAN data summary chart (1:5000 ft scale) for Well A. Columns from left to right, measured depth (MD); true vertical depth (TVD); MWD gamma ray; RoqSCAN gamma ray; bulk mineralogy summary curve (key minerals, yellow = quartz, pink = K-feldspar/plagioclase feldspar, greens and browns = individual clay species and blue = calcite); individual mineral species from quartz to calcite; measured porosity; pore size distribution; pore aspect ratio; RoqFRAC brittleness index (BI); rock types; gross lithological sections; optimized completion stages and well trajectory. Sample points are shown as circles within the quartz column.

RoqFRAC brittleness index (BI)				Rock Types			
Min.	Max.	Avg.		<29	30-50	51-69	>70
22	25	24	E	E			
22	33	28	F	F			
28	41	35	G		G		
29	52	41	H		H		
43	62	53	I			I	
53	70	62	J			J	
57	70	64	K			K	
68	79	74	L				L

Table 1 RoqFRAC brittleness index (BI) and its relationship to key rock types. Rock types are defined by both compositional and textural mineralogical data.
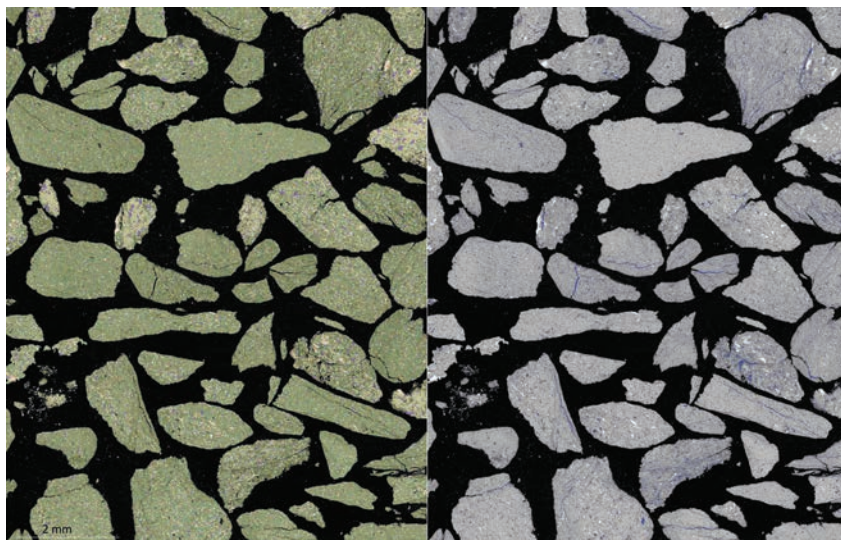
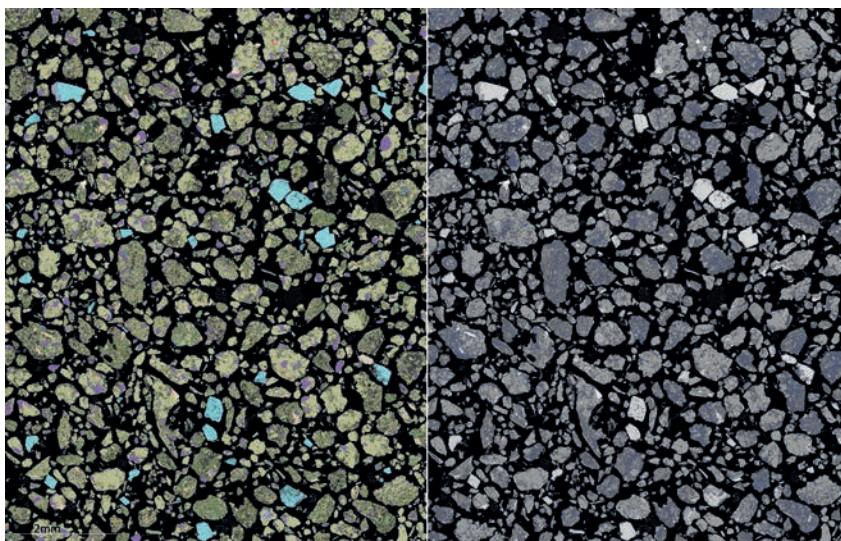*Figure 4 Sample depth 11,100 ft MD, Well A. Left image is a mineral map showing individual cuttings particles (dominant mineralogy is mixed clay/illite/muscovite (green shades) with minor v. fine quartz (yellow shade). Right image is a pore map showing >1 μm pore system (blue shade). Although some of the elongate pores are likely to be artifacts, others are associated with micro-laminations. However, the majority of the pore system is dominated by <100μm sub-rounded to sub-elongate pores. Note scale bar and black colour represents fixing medium.*

Figure 5 Sample depth 14,100 ft MD, Well A. Left image is a mineral map showing individual cuttings particles (dominant mineralogy is quartz (yellow shade) with minor calcite (blue shade) and mixed clay/illite/muscovite (green shades). Right image is a pore map showing >1 μm dual pore size system (blue shade). Note scale bar and black colour represents fixing medium.

Transition Zone (10,600 ft MD-10,850 ft MD) shows a gradual increase in mixed clay content and a reduction in pore size.

This transition zone has been interpreted as rock types H and I.

Section B (10,850 ft MD-12,000 ft MD) represents the middle part of the pay zone and is dominated by mixed clay (avg. 40.31%) illite/muscovite (avg. 21.12%) and very fine-grained quartz (avg. 27.7%). Pore size is on average much smaller than in Section A, and dominantly <100μm, but is still dominantly sub-rounded to sub-elongate and likely associated with micro-laminations. Section B is a zone of ductile rock and has been interpreted as dominantly rock types F and G. Figure 4 is a high-resolution mineral map of a sample typical of Section B.

Section C (12,000 ft MD-14,400 ft MD) represents the upper part of the pay zone and is dominated by quartz (avg. 53.88%) with minor calcite (avg. 5.05%) mixed clay

(avg. 13.56%) and illite/muscovite (avg. 11.19%). This section is dominated by a dual pore size system with 50% of the pores <100μm and 50% >100μm. The larger-sized pores are more rounded while the smaller-sized pores are sub-elongate. Section C is a zone of brittleness and has been interpreted as dominantly rock types J, K and L. Figure 5 is a high-resolution mineral map of a sample typical of Section C.

Completion design

There are two common types of completion design. The most commonly adopted design is the geometric completion, which assumes a homogeneous geomechanical near-well bore system where each stage is of a similar length and the completion strategy per stage is similar.

The other common type of completion design is the optimized (sometimes called geologic) completion which
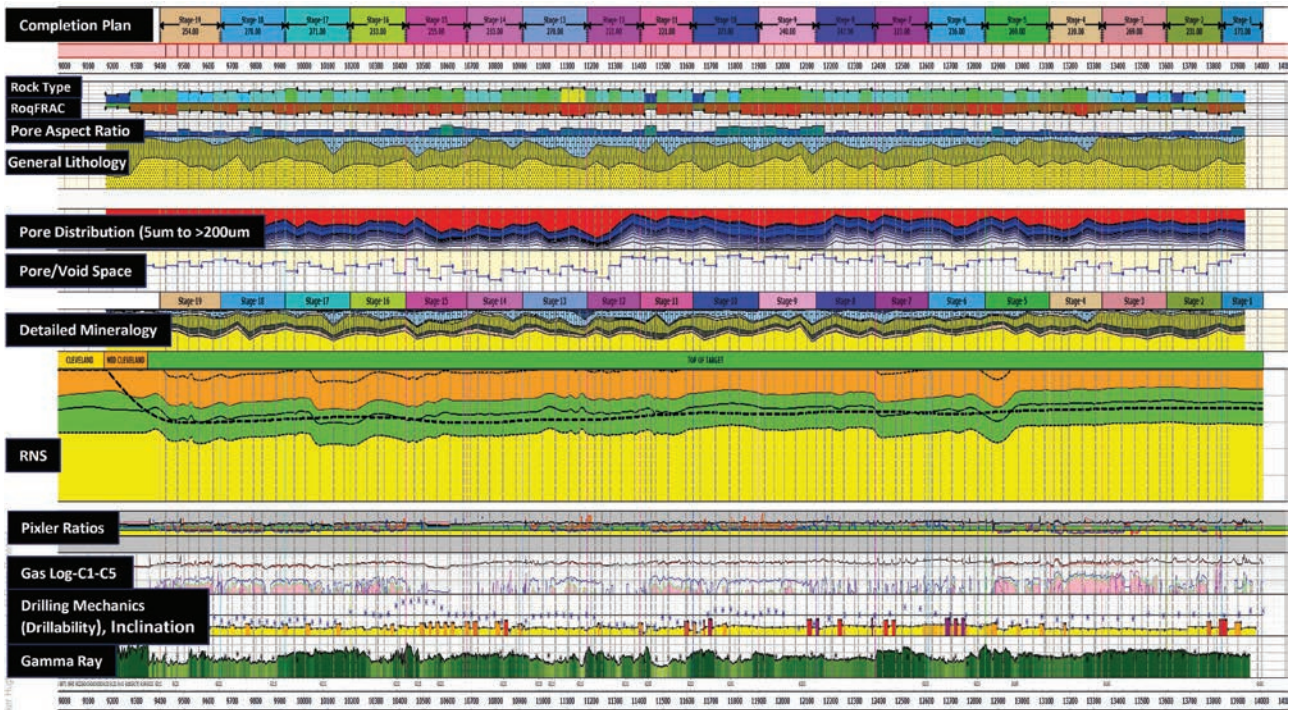
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Figure 6 *Composite optimized completion plot for Well A.*
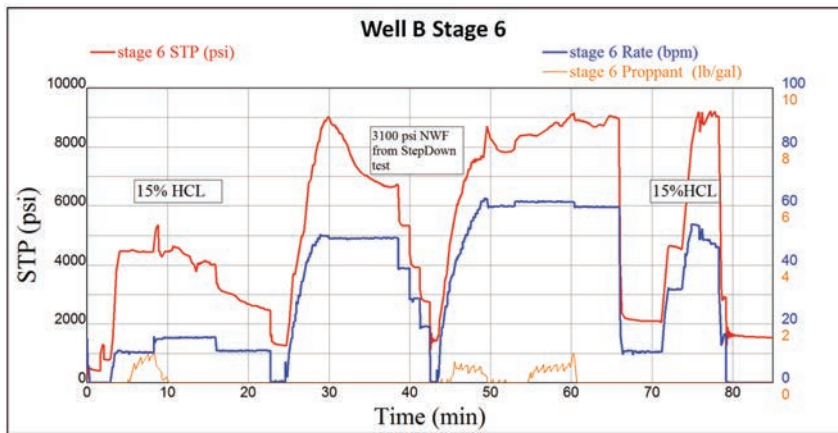

Figure 7 *Well B, stage #6. The stage was skipped because of very high NWF.*

takes into account the near-well bore geological and geomechanical heterogeneities and applies this knowledge such that individual stages are of an optimal length to take into account geological and engineering complexities and the completion strategy per stage is optimized for that stage.

Well B was completed using a typical geometric 'Plug and Perf' frac design for this Play, which included an 80 bpm slick water pumping rate, 20 stages of 228 ft length with five 40-ft equally spaced clusters per stage, 50 ft stage spacing and 340,000 lbs of 30/50 mesh (300 μm-600 μm) sand per stage.

Well A was completed using an optimized design based on all available well data (RoqSCAN mineralogical data, drilling rate of penetration (ROP), weight on bit, LWD gamma and measured mud gas data), (Figure 6).

Frac stages were grouped based on similar rock properties derived from the Rock Type scheme and the brittleness index (BI). Drilling mechanics was used to identify any abnormalities. Perforations for five clusters per stage were picked based on C1-C5 hydrocarbon shows together with pore shape data. Well A ended up with a final optimized completion design of 21 stages (one extra when compared to Well B) with measured lateral stage length between 163 ft and 324 ft and cluster spacing from 16 ft to 71 ft, with a maximum of five clusters per stage.

Results from the Geometric Completion Model, Well B

The offset Well B underwent hydraulic fracturing first and experienced many engineering problems, most notably con-

cerning proppant placement and efficient formation break-down. It was only possible to pump the full designed mass of 300,000 lbs of sand in three of the stages. In 13 stages, sand injection was cut short because surface treating pressures (STP) became too high. Figure 7 highlights some of the engineering problems from one stage, stage #6, where, based upon other wells in the area, 15% hydrochloric acid (HCL) breakdown fluid was used in conjunction with a step down test (used to quantify perforation and near-wellbore pressure losses). The step down test indicated a very high 3100 psi of near wellbore friction (NWF) drop and 265 psi perforation friction. Two phases of 35 bbls of 15% HCL acid had no effect on reducing NWF and, consequently, stage#6 was abandoned because of high pressure.
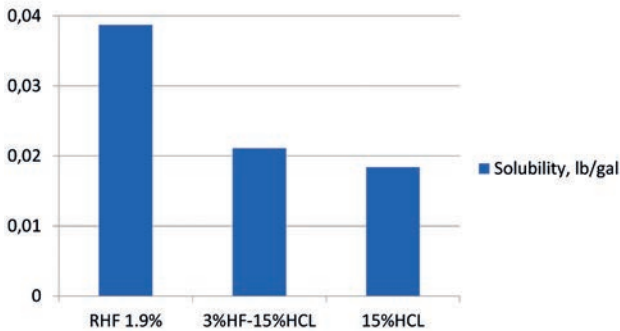
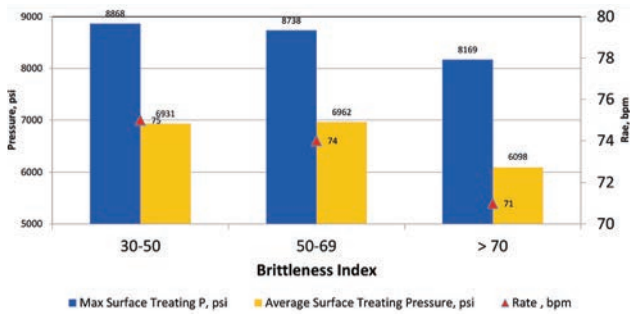*Figure 8 Well A acid solubility test.*

Figure 9 Well A STP and BI.

Results from the Optimized Completion Model, Well A

With the additional mineralogical data collected in Well A, additional steps were taken in an attempt to address some of the challenges identified in the Well B frac treatment.

2 Capillary Suction Time Test (CST)

As the RoqSCAN data had identified a volume of clay through the bore hole with particularly high volumes in Section B (between 10,850 ftMD and 12,000 ftMD) it was decided to perform a CST to determine clay sensitivity and acid solubility as a way of identifying an alternative break-down fluid to the standard 15% HCL. The results of the CST on a range of clay-rich samples through the wellbore suggested that the samples had a low sensitivity to fresh water and a retarded 1.9% hydrofluoric acid (RHF) showed the highest solubility, as shown in Figure 8. Based on the additional testing results, a new 1.9% RHF breakdown fluid was used.

2 Surface treating Pressure (STP)

The STP for those clusters placed in the more ductile part of the well, i.e. Section B where the rock types are dominantly F & G and the BI averaged 30-50, was higher than for the clusters located in the more brittle parts, i.e. Sections A and C where the rock types are dominantly J, K and L and the BI averaged >70. Figure 9 shows the maximum and average surface treating pressures for different BI values. Maximum STP is reduced as the BI increases, thus confirming that in the near wellbore environment, brittleness is a key factor in fracture initiation and propagation.

To further support this statement, a frac treatment chart of two Well A stages (1 and 14) for differing BI indices ranging from 25-70 is shown in Figure 10. The clear difference in fracking ductile and brittle zones can be seen in these charts. Stage 1 (BI of 70), depicted in red in Figure 10 below, demonstrates that more brittle rock breaks and reaches the designed pumping rate much faster than the equivalent more ductile rock of stage 14 (BI of 25) depicted in blue below.
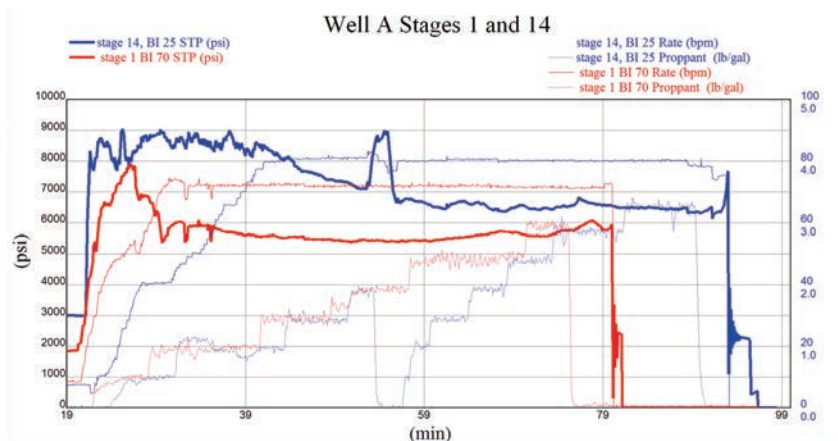

Figure 10 Well A STP for stage 1 (Section C, Rock Types J and K, BI 70) and stage 14 (Section B, Rock Types E and F, BI 25). Brittle rock in stage 1 achieved the target pumping rate faster than the more ductile rock in stage 14. stage 1: 1850 psi NWF pressure drop after 8 min; stage 14: 1600 psi NWF pressure drop after 25 min.

	Well A (optimized)	Well B (geometric)
Stages	21	20
Acid	1.9% RHF based	15% HCL
Screen out	0	3
Abandoned stages	0	1
Stages <100% of proppant	2	13
Average proppant per stage	309,000 lbs	226,000 lbs
Average stages per day	5.3	3.3

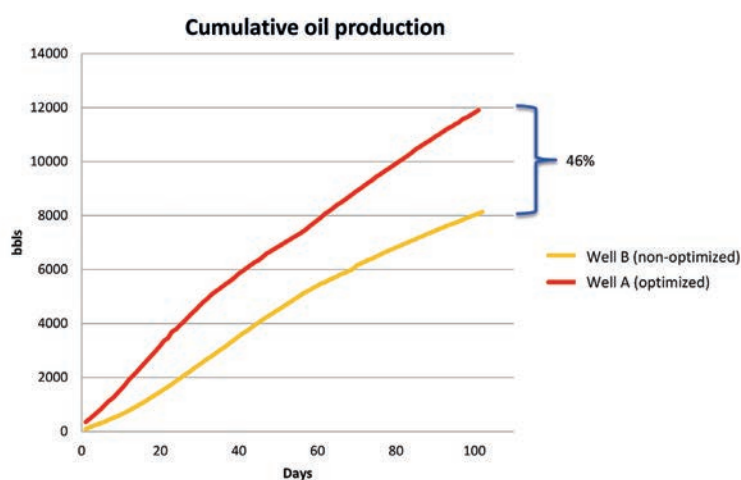**Table 2** Well A and Well B frac treatment summary.

Figure 11 Well A (blue) and Well B (orange) post frac cumulative oil production.

A thorough understanding of Rock Types and BI along the wellbore and its relation to STP is a key component of building an optimized completion plan. In the optimized completion model, the aim is to, as far as possible, group similar Rock Types and thus BI values together in one stage, i.e. make each stage as homogeneous as possible. Combining dominantly ductile and brittle rocks into one stage will likely create breakdown and fracturing only in the brittle portion of the stage, thus leaving the more ductile part unstimulated. This creates an inefficient or ineffective stage.

Due to the improved mineralogical understanding of the wellbore and the incorporation of this knowledge into the optimized completion model, the fracture treatment of Well A was completed successfully with zero screen-outs. Zero screen-outs meant no disruption to the frac operation (e.g. cessation of pumping, wellbore clean-out) and this improved efficiency helped to contribute to an impressive 5.3 stages completed per day. An engineering summary comparing the fracture treatment of both Well A (optimized) and Well B (geometric) is presented in Table 2 below.

Cumulative production

After 115 days of post treatment oil production, Well A (optimized) is outperforming the offset Well B (geometric) by 46% (Figure 11).

Conclusions

This paper has demonstrated the effectiveness of an optimized completion strategy versus a standard geometric completion strategy in the geologically complex Cleveland Sands Play of the Anadarko Basin. An optimized completion strategy was possible because near-wellbore quantitative geological data was collected and analysed and combined with drilling and log data. These data were then used to a) determine key engineering parameters and b) design an optimized completion model that both honored the geological heterogeneities (changing rock types and brittleness) and defined the best completion strategy in order to maximize an efficient frac operation and improve cumulative hydrocarbon production.

RoqSCAN mineralogical analyses were performed on 104 samples collected from 50 ft spacing along the length of the lateral well. Based on the mineralogical data, the well was zoned into three gross sections, demonstrating the vertical and lateral heterogeneity through the pay zone. Each Section was then further classified into rock types based on compositional and textural mineralogy and brittleness (BI).

Rock types and brittleness (BI) correlate with frac surface treating pressure, supporting the basis for stage spacing based on similar rock type and BI values. Both maximum and average surface treating pressures for ductile zones were

found to be typically higher than for brittle zones. We found that the initial treating pressure for brittle stages could be as high as that for ductile Stages but less time was required to remove near wellbore friction pressure and reach the target rate for brittle rock.

The optimized completion frac treatment of Well A showed superior operational effectiveness and production over the geometrically completed Well B because of a better understanding of the lithological heterogeneity along the well bore and the application of this knowledge into the completion and engineering design.

Cuttings analysis using a tool such as RoqSCAN is a cost-effective and convenient solution applicable for all types of geological plays and provides the necessary data to allow for the design of an optimized completion model which, from experience, is likely to generate a more efficient frac operation and improve cumulative hydrocarbon production. In today's low oil price environment, this type of strategy is an effective and sensible approach to maximizing return on investment (ROI).

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