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Integration Of Ultra-High-Resolution Nano Tracers in Flow Diagnostics with a Multi-stage Completion Program For Post-Frac Flow Assurance, Fault Evaluation and Well Spacing Optimization in Eagle Ford Shale

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Abstract

Multi-stage hydraulic fracturing stimulation and completion programs in unconventional wells now account for up to 70% of total well costs. Faced with increased completion intensity, reservoir and geological complexities, and economic pressures, upstream operations must take a serious look at increasing their efficiency regarding the use of completion money and ensuring increased production results.

The future development and completion designs must be validated by cost-effective and accurate flow mapping measurements that deepen insight into complex reservoir flow performance and geological risk assessment, right-size the multi-bench well spacing, and focus on data-driven stimulation designs that optimize economics.

This paper highlights one such effort in a multi-well tracing project in Eagle Ford Basin. A novel and cost-effective ultra-high-resolution nanoparticle tracer played a key role in delivering useful data that led to a comprehensive understanding of the reservoir, geological faults, and optimize stimulation efforts at a stage level. Additional multi-well studies in turn led to the development of a full understanding of inter-well communication, fracture-driven interactions flow characterization, and optimizing well spacing.

The state-of-the-art, ultra-high-resolution nanoparticle tracers were added to each stage during completion for flow profile mapping and fault evaluation. In addition, a sampling campaign of adjacent wells was initiated to identify potential communication between offset and traced wells. The data integration of the nanoparticle tracers with offset wells pressure monitoring helped to improve the target reservoir development approach and provided a live performance flow profile for the entire development. This data was also used to optimize completion designs, stage and well placement strategies, and significantly enhance reservoir understanding and geological fault impacts on stage-level production.

Development Overview and Study Objectives

The Eagle Ford shale is a Late Cretaceous age sedimentary rock formation and consists of an organic-rich marine shale underlying much of South Texas. The Eagle Ford (EF) was discovered in 2008. This shale formation has a high carbonate content (up to 70%), which makes it brittle and facilitates hydraulic fracturing. During the Cretaceous time, the tectonic movements caused the land masses in the south-east, in the direction of the Gulf of Mexico, to be pressed down. These movements caused a steep slope in the geological layers and uplifted once submerged organic-rich areas onshore. For this reason, the depth of oil and gas bearing layers of the Eagle Ford varies anywhere from one to two miles deep. The average thickness is approximately 240 ft.

As illustrated in Figure 1, the EF formation was deposited on a large carbonate platform centered on the San Marcos Arch, which developed at the end of the early Cretaceous. The Edwards Shelf break represents the southern limit of this large carbonate platform. Total EF isopach thickness is concentrated in the Maverick Basin and thins out over the San Marcos Arch (Figure 2). Deposition extends

northeast of the arch where fluvial deposits from the Woodbine group become prominent. Deposition of a thick interval of the EF occurred in this low, the organic-rich mudstone facies, in an anoxic environment.

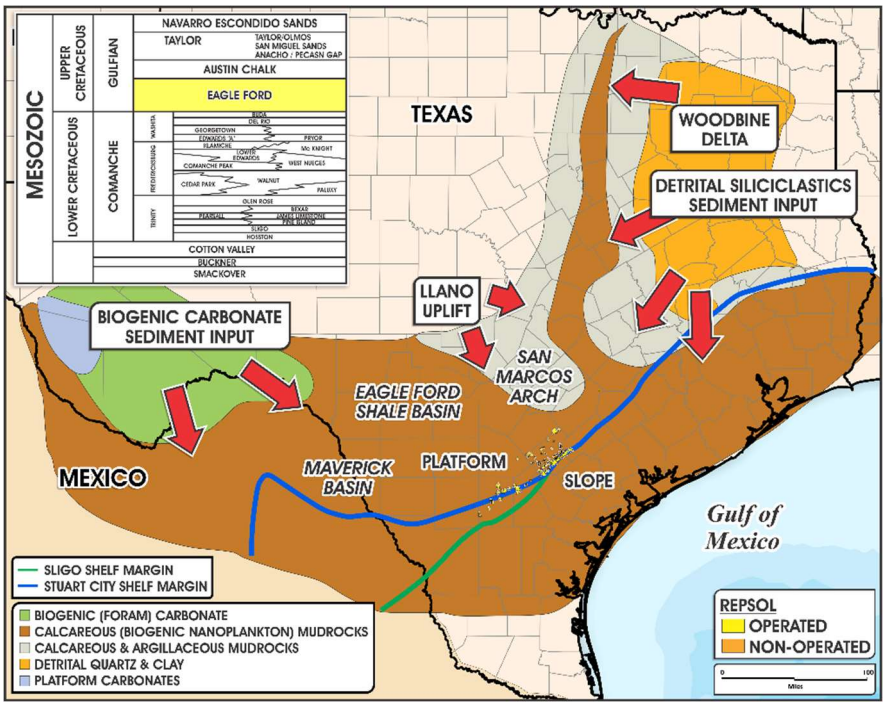

Fig. 1 – Eagle Ford shale depositional model

Contact with the Buda Limestone below is sharp and considered an unconformity. The Austin Chalk (AC) / EF contact represents a shift from the stratified, oxygen-poor waters of the EF to the mixed oxygenated waters of the AC, allowing for increased carbonate production. The contact with the overlying AC is difficult at times to identify on the logs.

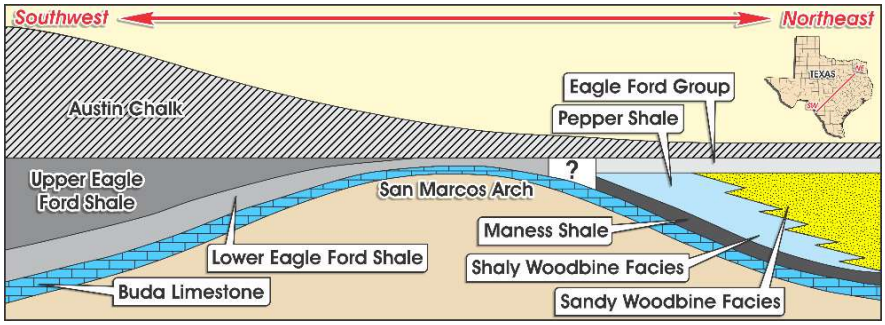

Fig. 2 – Eagle Ford regional cross section

The Lower Eagle Ford (LEF) is the main target across the play with depths from ~8,000 ft true vertical depth (TVD) and deeper in the black oil window to over 13,000 ft TVD in the dry gas window. The LEF is generally thickest to the east.

On average, the reservoir exhibits total porosity greater than six percent, total organic carbon greater than four percent, and average water saturation less than 30%. Historical development of the LEF has targeted the basal high-resistivity, high-porosity zone, where operators tend to stagger the wells about 40 to 50 ft apart to achieve maximum recovery potential in the whole interval.

The Upper Target defines a single landing zone that straddles both the Upper Eagle Ford (UEF) and basal AC. For the purposes of this publication, the UEF is generally considered a secondary target and has lower petrophysical properties than the LEF, total porosity averages six to seven percent and an average of 40% water saturation. The Basal AC has higher porosity (six percent and greater), low clay content, and an abundant number of natural fractures. The thickness varies but can be as thick as 200 ft in the area being investigated in this paper. Figure 3 illustrates the LEF / UEF landing zones and suspected fracture geometry.

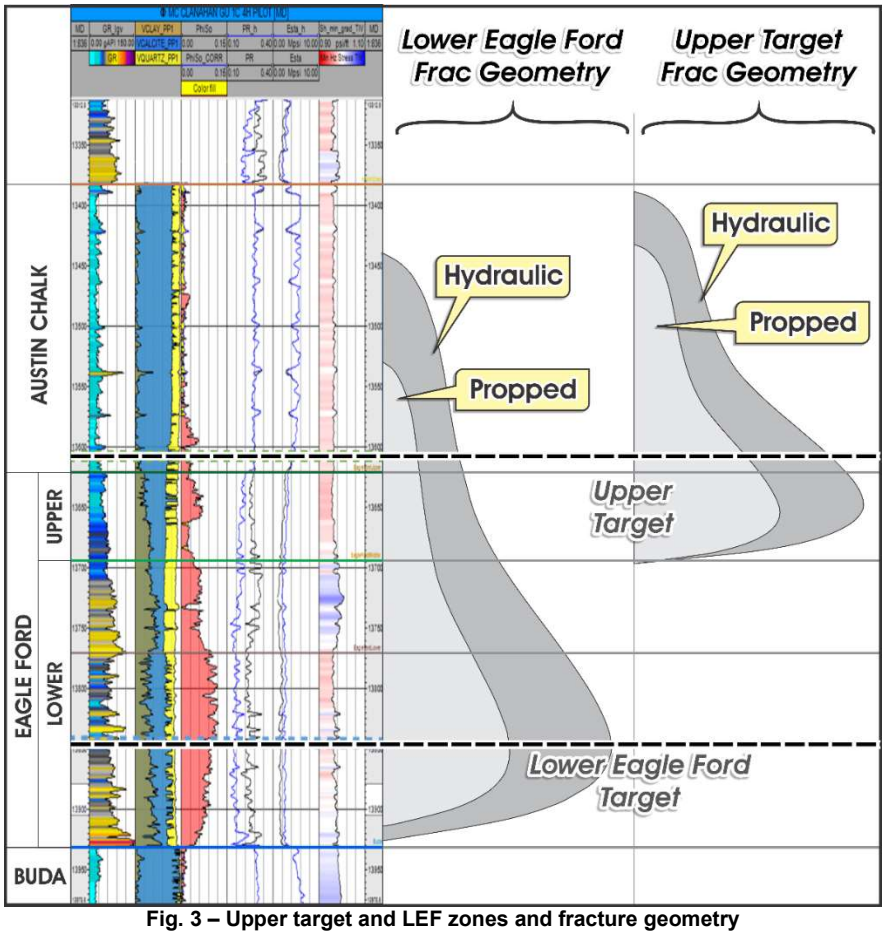

Fig. 3 – Upper target and LEF zones and fracture geometry

This study aims to increase the understanding of well-to-well communication, in-well stage-by-stage cleanup and contribution, and effect of fracture-derived interactions leading to a comprehensive understanding of the subsurface, optimization of the stimulation design, and better alignment of horizontal and vertical spacing to generate maximum business value. This undertaking was aided by use of state-of-the-art nanoparticle tracers, high resolution pressure gauges, and real-time analysis of fracturing data.

Ultra-High-Resolution Nanoparticle Tracer Technology Overview

The intensified focus on the production performance of unconventional wells, combined with the complexities of subsurface reservoir quality and stage-level production, has significantly heightened the economic pressures on oil and gas companies. In this challenging and dynamic environment, operators face increased demands to gain deeper insights into complex reservoir performance, optimize well spacing, and implement data-driven stimulation designs based on stage-level production measurements, all to boost production flow while adhering to increasingly tight budget constraints.

Efforts to optimize production and maximize estimated ultimate recoveries (EUR) must increasingly focus on multi-stage hydraulic fracturing and completion designs, which collectively can account for up to 70% of total well costs. This process is crucial for unlocking and enhancing hydrocarbon flow from ultra-low-permeability reservoirs. The main objective is to maximize reservoir contact by exposing large surface areas within the reservoir through fracturing stimulation, which creates and interconnects hydraulic and natural fractures (Shokanov et al. 2003).

With current completion designs, the production results of multi-stage hydraulic fracturing treatments, when reported down to the individual stage level, are significantly lower than many oil and gas companies expect. Several stage level production mapping studies across various shale basins in North America have reported that up to 30% of the stages and clusters do not produce (Lindsay et al. 2018).

Furthermore, the current geometric completion designs, coupled with rock heterogeneity, a brute force approach involving increasing volumes of sand and water, and diminishing returns, present significant economic challenges for modern wells. This is particularly true for unconventional wells, where it is essential to access affordable and risk-free stage-by-stage flow profiles to identify non-productive stages. A method that maximizes production flow across the horizontal lateral can help minimize unnecessary costs and reduce onsite emissions by eliminating non-economic frac stages during multi-stage hydraulic fracturing operations.

As operators embark on infill development in the context of increasingly tight well spacing and uncertain economics, the issue of fracture hits has become a critical element in asset development strategies (Figure 4). It's important to note that direct fracture hits only account for 12% of detected events; the majority — approximately 82% — are associated with fluid migration between the existing "parent" well and the newly drilled "child" well (Shokanov et al. 2021). While fluid migration has a minimal and short-lived impact on production, its absence would result in substantial areas between the wells remaining unstimulated, potentially leaving significant reserves stranded. Thus, it is essential to accurately assess and quantify the detected inter-well flow communication events (Shokanov et al. 2021).

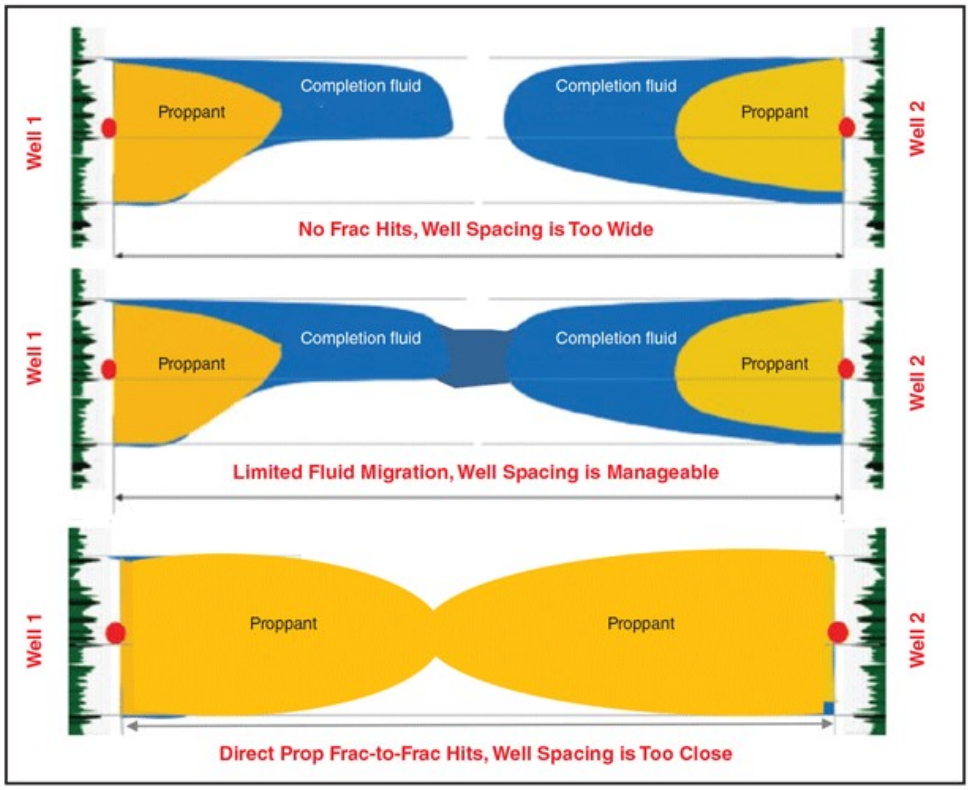

Fig. 4 – Fracture hit types and impact in unconventional wells

However, with the exception of a few engineered "science" wells, data on critical fracture hits and stage-level production have been largely inaccessible for over 99% of completed land wells (Shokanov et al. 2020). To bridge the significant economic gap between specialized engineered science wells and mainstream applications, a uniquely engineered portfolio of ultra-high-resolution nanoparticle tracers has been developed and deployed. These tracers are designed to deliver stage-level flow data that was previously available only for a limited number of wells.

Field-proven nanoparticle-based tracers consistently provide accurate, near real-time detection that surpasses the capabilities of conventional chemical liquid tracers and DNA sequencing products, all at a comparable cost that represents only a fraction of the total expenses associated with modern completions. Enhanced by the latest advancements in nanoparticle science and advancement, these robust, non-radioactive, and non-hazardous tracers are engineered with subatomic spectroscopic measurement techniques. This allows them to effectively map well production distribution, assess the performance of each stage, monitor cross-well interference, and evaluate reservoir conditions.

Easily deployable, the distinctly tagged and non-intrusive nanoparticle tracers are designed to maintain stability even at extremely high temperatures. In contrast to standard chemically based soluble tracers, these nanoparticle tracers remain intact within the fracture network, allowing for continuous on-site monitoring of the flow profile for up to 10 months.

The ultra-high-resolution nanoparticle tracers are able to convey much more information about the fractures in the reservoir, from the flow characteristics to the fracture's conductivity. Easily deployed, clearly tagged, safe, non-radioactive tracers can maintain stability at excessive reservoir temperatures (up to 2,000°F), have a light specific gravity of 0.9 – 1.17 g/cm^3, and withstand the high closure stress (up to 10,000 psi) which compares very favorable to the limitations of standard chemically soluble tracers. The ultra-high-resolution nanoparticle tracer technology has also provided 220 distinct tracers, allowing for great versatility in tracing all fracturing stages in a single or multiple new horizontal wells under development. Figure 5 shows the relative size to other tracers and gives some properties of the nanoparticle tracer. The nanoparticle tracers remain intact within the fracture networks, allowing continuous on-site monitoring of the flow profile.

Physical properties	FloTrac tracers
Specific gravity, g/cm3	0.92 – 1.17
Temperature limit, F	2,000
Number of FloTrac tracers	220 unique tracers

Fig. 5 – Ultra-high-resolution nanoparticle tracer shown in comparison to sizes of popular fracture sands

Acquiring post-fracture flow profiles, which are critical for optimizing multi-stage hydraulic fracturing programs, has previously been largely unavailable and, when accessible, has typically been a cumbersome and highly costly endeavor. Many standard diagnostic methodologies require specialized downhole modifications and often yield inferred measurements rather than direct assessments of the flow profile.

For example, production logging tools necessitate wireline intervention but only offer a medium level of detection accuracy for multi-phase flow, particularly in the case of comingled flow along the horizontal lateral, providing merely a brief snapshot for production profiling during the wireline operation. Similarly, microseismic completions can generate data points related to rock shear failure during hydraulic fracturing but do not provide direct insights into the production profile or the degree of inter-well communication. In contrast, DNA sequencing products are limited to the localized near-wellbore area and require an expensive and extensive process for drill cuttings sampling and analysis.

Current Landscape of Flow-Profiling Technologies

Conventional liquid chemical tracers, which utilize water- or oil-soluble chemical substances, have been utilized as tools for reservoir surveillance for many years. Various types of tracers, including fluorescent tracers, DNA fingerprints (Zhang et al. 2020), ionic compounds, organic materials, and radioactive diagnostic isotopes, have been employed to assess fracturing performance and help evaluate the effectiveness of multi-stage hydraulic fracturing stimulation. However, due to clear environmental concerns and issues related to disposal, the use of tracers containing radioactive isotopes has largely declined.

Due to their soluble characteristics, conventional chemical tracers must be customized for each specific fluid type. This often necessitates the use of more complex and sometimes exotic chemical formulations for just a single stage, which significantly drives up the costs of chemical tracers in modern multi-stage hydraulic fracturing completions. Furthermore, once liquid-based tracers have been pumped, they dissolve, disseminate quickly, and are flushed from the conductive proppant pack, thus shortening the effective stage-level production monitoring period significantly. Therefore, because of cost, occasionally inconclusive accuracy, cross-well contamination, and downhole temperature restrictions (limited to 350°F), the use of contemporary chemical tracers is realistically limited to “science” wells.

Conventional tracer testing is also significantly limited by the time required to achieve a comprehensive interpretation of the test results. Typically, this process is conducted by an offsite analytical laboratory, which usually has a minimum turnaround time of three weeks on average. This extended timeline is due to lengthy sample preparation procedures, the high cost of instrumentation, the delicate sample dissolution process, and the specialized reagents required for analysis.

One of the most significant drawbacks of conventional chemical tracers is their tendency to generate unnecessary signals that can be mistakenly interpreted as “fracture hits.” A fracture hit is generally defined as a fracture-driven inter-well communication event,

where the hydraulic fracturing treatment being pumped into a new well, referred to as the "child" well, impacts an adjacent well, often termed the "parent" well (Gupta et al. 2021; King et al. 2017).

For instance, in a multi-zone well stimulated using a zipper fracturing method, where most pay zones are hydraulically fractured sequentially — one well pumping while the other is undergoing wireline operations — a typical stacked pay shale well may exhibit a predominant fracture filled with sand proppant, alongside a secondary fracture network featuring very small apertures or open fissures. In such cases, chemical tracers often infiltrate these small fissures, leading to multiple “false positives” that incorrectly indicate that all fractures are communicating and impacting production. However, because of the residual proppant-fracture conductivity, once pumping stops, it is primarily the sand-packed fracture that continues to contribute to production, while the natural fractures quickly re-seal, resulting in minimal actual inter-well communication.

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In contrast, fiber-optic-enabled distributed temperature surveys (DTS) and distributed acoustic sensing (DAS) provide a high degree of detection accuracy and enable long-term production profiling (Huckabee 2009). However, these systems, which must be integrated during the completion operation, require significant downhole modifications, including specialized oriented perforations, and demand meticulous attention to perforation phasing and cement integrity. Unfortunately, these systems often experience high failure rates due to fiber damage and signal disruption during plug-and-perf operations.

Some references for fiber optic used in well for DTS and DAS are:

Furthermore, the associated costs are considerable, often exceeding the budgets of most oil and gas operators, especially given the current economic climate and the high risk of obtaining limited data. Depending on their complexity, the permanent installation of fiber optic DAS and DTS systems can add as much as $1 million per well to the total completion costs. These challenges, along with the prohibitive costs of conventional tracers and existing diagnostic technologies, have driven the adoption of next-generation ultra-high-resolution nanoparticle tracers and “intelligent” flow-diagnostic workflows. Table 1 compares the current landscape of intelligent flow-technologies (Shokanov et al. 2020). The ultra-high-resolution nanoparticle tracers provide precise and actionable performance-flow-profile data. This allows the operator to optimize well placement and improve field development strategies, resulting in reduced costs associated with well completion and multi-stage hydraulic fracturing.

	Production Logging (PLT)	Chemical Tracer	Fiber Optic (DAS & DTS)	Nanoparticle Tracer
Type of Technology	Logging	Chemical	Downhole Fiber Optics	**Smart Tracers**
Temperature Limit	700°F	350°F	500°F	**2,000°F**
Detection Accuracy	Medium	Low	Very High	**High**
Production Profiling Timeline	Short-Term	Middle-Term	Long-Term	**Long-Term**
Deployment Requirements	Intervention with Logging	Multiple Tracers per Stage	Downhole with Completion	**Single Tracer per Stage**
Mobile Lab with Onsite Analysis	Yes	No	Yes	**Yes**
Results Turnaround Time	2 Weeks	3 Weeks	3 Weeks	**Near Real-Time**
Precision in “Fracture Hits” Mapping	No	Medium	No	**Very High**
Cost to E&P Operators	High	High	Very High	**Low**

Table 1 - Current landscape of flow-profiling technologies

Tracer Field Deployment and Quality Assurance

The operator commenced the development of the Wess 5-7 Pad D in the Eagle Ford Basin, located in Karnes County, TX, with several new well completions. The initial plan involved fracturing and completing the first three new wells (D1H, D2H, and D4H) in Group #1 using a triple zipper fracture sequence. Upon successfully completing these three wells, operations would then shift to Wells D3H, D5H, and D6H in Group #2. The new Well D4H from Group #1 was designated as the primary monitoring well, featuring extensive frac, pressure (e.g., DFIT or mini-frac) test, and stage-level flow diagnostic surveillance. This included the use of unique ultra-high-resolution nanoparticle tracers for each stage to analyze single well and inter-well flow communication. The gun barrel diagrams (post-drill) for both groups of wells are shown in Figure 6.

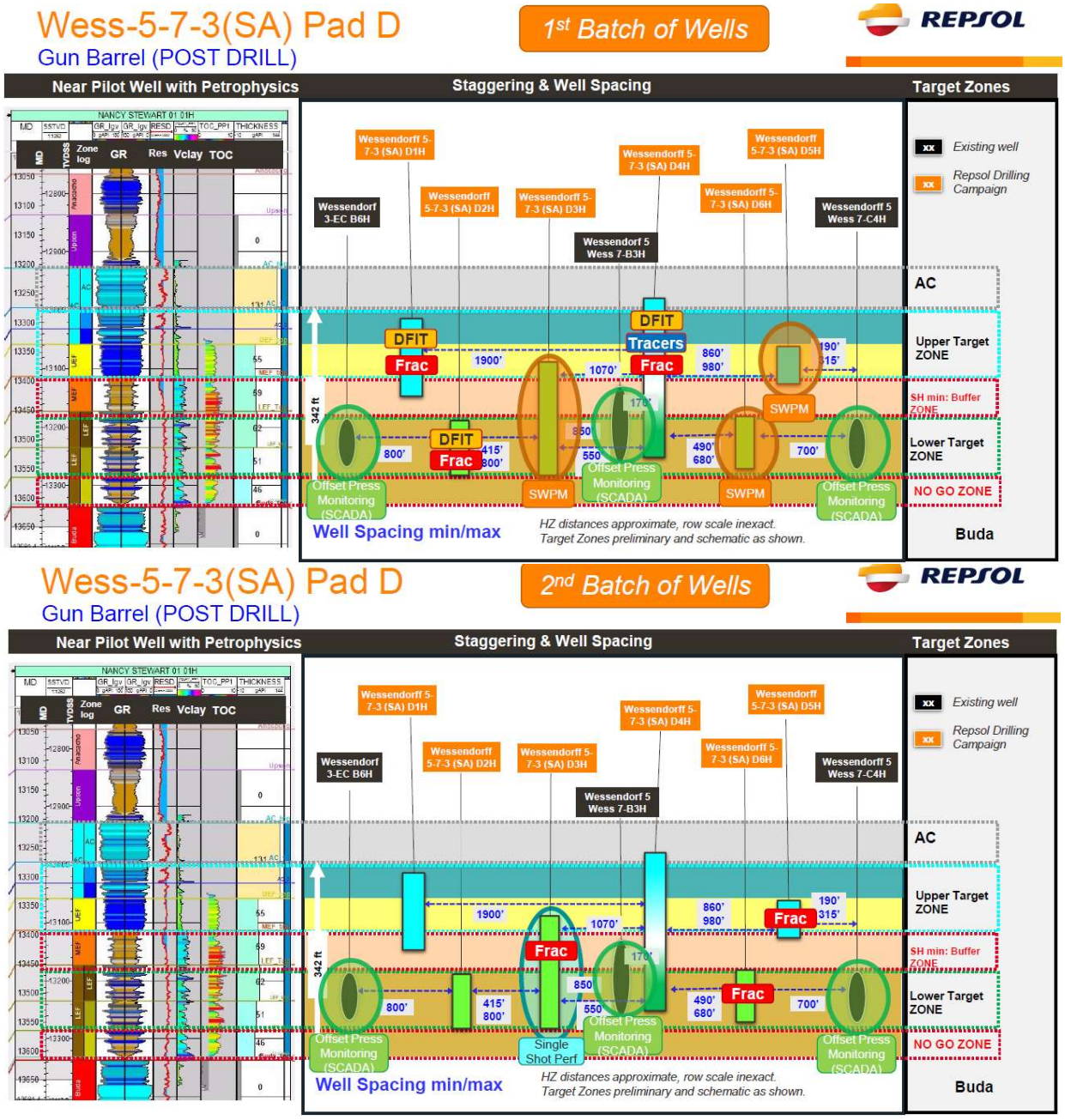

Fig. 6 – Gun barrel diagrams of Group #1 and Group #2

The D4H completion program involved 63 frac stages using slickwater fracture fluid and 100-mesh frac sand. Each stage was designed to be 150 feet long, with a total horizontal lateral length of 9,500 feet. The proppant or sand intensity was set at 3,000 pounds per foot. The designed pumping rate was 90 barrels per minute (BPM), with each stage requiring 450,555 pounds of sand and 10,097 barrels of slurry. A friction reducer and biocide were added during the pumping process. The cluster design included 9 clusters per stage, equipped with composite frac plugs and special deep penetration perforation shaped charges with a 1-foot gun length, 3 shots per foot (spf), and 0-degree phasing.

For each stage, a unique ultra-high-resolution nanoparticle tracer was designed and manufactured. In total, 63 unique nanoparticle tracers were produced for the 63 stages of this well. Each stage utilized 7 pounds of nanoparticle tracer, injected at a concentration of 15.5 parts per million (ppm). The production of each ultrahigh-resolution nanoparticle tracer adhered to rigorous manufacturing, quality control, and testing protocols. Prior to deployment, each tracer underwent stringent lab sub-atomic testing and validation processes to ensure optimal downhole performance and flow efficiency. Additionally, all nanoparticle tracers were pre-mixed in a specialized liquid to ensure occupational safety for the tracer crew and to ensure accurate injection during each stage. The nanoparticle tracers are solid, inert, non-radioactive, and non-hazardous materials, hence not interacting with frac fluids.

Prior to the project's start, the tracer equipment rig-up and deployment were thoroughly discussed with the frac crew and operator's field superintendents. The frac pumping company facilitated access to the blender and provided a radio for communication with the frac crew and the data/control van. All nanoparticle tracers were pre-mixed in a specialized suspension liquid and delivered onsite in 1-gallon containers (jars). During pumping, the nanoparticle tracers were added to the frac blender tub to ensure excellent mixing and dispersion. The nanoparticle tracer injection commenced after the stage pad phase when frac sand was entering the frac blender and was halted just before the stage flush phase. This approach enabled uniform nanoparticle tracer placement within the hydraulic fracturing (prop area inside the frac) for each stage and prevented cross-stage tracer contamination (Table 2).

Stage	Stage Type	Clean vol (bbls)	Cum. Clean (bbls)	Density (ppg)	Slurry vol (bbls)	FR (gals) @ 1 gpt	Bio (gals) @ 0.2 gpt	Stage Prop (lbs)	Rate (bpm)	Time (min)
1	Slickw ater	12	12	0	12	0.5	0.1	0	10	1.2
2	Acid	48	60	0	48	0.0	0.0	0	10	4.8
3	Slickw ater	714	774	0	714	30.0	6.0	0	90	7.9
4	Slickw ater	700	1474	0.25	708	29.4	5.9	7,350	90	7.9
5	Slickw ater	700	2174	0.5	716	29.4	5.9	14,700	90	8.0
6	Slickw ater	1000	3174	0.75	1034	42.0	8.4	31,500	90	11.5
7	Slickw ater	1200	4374	1	1254	50.4	10.1	50,400	90	13.9
8	Slickw ater	1200	5574	1.25	1268	50.4	10.1	63,000	90	14.1
9	Slickw ater	1200	6774	1.5	1281	50.4	10.1	75,600	90	14.2
10	Slickw ater	1200	7974	1.75	1295	50.4	10.1	88,200	90	14.4
11	Slickw ater	500	8474	2	545	21.0	4.2	42,000	90	6.1
12	Slickw ater	390	8864	2.25	430	16.4	3.3	36,855	90	4.8
13	Slickw ater	390	9254	2.5	434	16.4	3.3	40,950	90	4.8
14	Flush	357	9611	0	357	15.0	3.0	0	90	4.0
		9611			**10,097**	**401.7**	**80.3**	**450,555**		**117.5**

Table 2 – Pumping schedule and tracer injection timeline highlighted during each stage (in green)

Frac operations began on June 25, 2023, and were successfully completed by July 2, covering a period of 27 days. The injection and deployment of all nanoparticle tracers proceeded as scheduled, without any interruptions or injection issues. Data from the nanoparticle tracer operations were recorded and streamed live to support personnel and office experts. Upon completion of well D4H, a nanoparticle tracer deployment report was submitted, including the injection log and the start and stop times for nanoparticle tracer injection at each stage.

Sampling Schedule for Traced and Offset Wells

The operator's Monitoring and Surveillance Group, in collaboration with the tracer experts, developed a specialized sampling schedule for D4H and 4 offset wells: B3H, D1H, D2H, and D3H. The sampling began at the start of flowback or production, with the goal of completing each round of sampling for all wells within a single day. A dedicated senior field tracer technician was responsible for collecting all samples under strict quality control and assurance protocols. Sampling points were placed at the wellhead flowline, upstream of the sand-trap equipment, to ensure that the most representative samples were taken as fluid exited the well. The first round of sampling occurred 15 days after flowback commenced, with subsequent samplings every 15 days until 60 days of production. Afterward, the frequency changed to every 30 days, continuing until 180 days of production. In total, 35 samples with each sample of 1 gallon were collected from all wells and analyzed in the sub-atomic analytical lab. The sampling work commenced on September 18, 2023, and completed on March 4, 2024. Table 3 outlines the sampling program for the Wess 5-7-3 pad.

	D3H	B3H	D4H	D1H	D2H
	4	7	8	8	8
	Wess 5-7-3 D3H	Wess 5 Wess 7 B3H	Wess 5-7-3 D4H	Wess 5-7-3 D1H	Wess 5-7-3 D2H
	New Well + SWPM	Parent Well	New Well + Tracers	New Well + DFIT	New Well + DFIT
	Monitor	Monitor	Treatment Well	Monitor	Monitor
Production Time [days]					
5					
10					
15	X	X	X	X	X
20					
25					
30	X	X	X	X	X
35					
40					
45	X	X	X	X	X
50					
55					
60	X	X	X	X	X
65					
70					
75					
80					
85					
90		X	X	X	X
95					
100					
105					
110					
115					
120		X	X	X	X
125					
130					
135					
140					
145					
150		X	X	X	X
155					
160					
165					
170					
175					
180			X	X	X

Table 3 – Sampling schedule for traced well D4H and 4 offset wells (B3H, D3H, D2H, and D1H)

Production Samples Analysis and Workflow

The collected samples were delivered to the sub-atomic analytical laboratory on the same day collected for comprehensive nanoparticle tracer analysis. Using a proprietary nano-extraction process, particles were extracted from both the oil and water phases of each sample. These particles were then analyzed using advanced, established techniques: energy dispersive X-ray fluorescence (EDXRF) and X-ray diffraction (XRD).

EDXRF is a non-destructive analytical technique used to determine the elemental composition of materials. EDXRF analyzers determine the elemental composition of a sample by measuring the fluorescent (or secondary) X-ray emitted from a sample when it is excited by a primary X-ray source. X-rays have a very short wavelength, which corresponds to very high excitation energy. When X-ray energy causes electrons to transfer in and out of these shell levels, X-ray fluorescence peaks with varying intensities are created and will be present in the final measurement spectrum. The peak energy identifies the element, and the peak height or intensity is indicative of its concentration for comprehensive qualification and quantification in elemental analysis. EDXRF technology is a non-distractive, portable, and comprehensive way to screen all kinds of particles for quick identification and quantification of elements.

XRD is a non-destructive technique that provides detailed information about the crystallographic structure, composition, and physical properties of nano particles. XRD is a rapid analytical technique primarily used for phase identification and the crystallinity of a sample. XRD is widely used for the identification of unknown crystalline materials (e.g., minerals, metals, oxides, and inorganic compounds). Many industries rely on proven XRD results to characterize materials, from basic product research all the way to quality control and quality assurance. A sample is placed in the path of an X-ray beam. X-rays diffract through the crystal and into a detector. The beam and detector are rotated through a range of angles. The angles at which the crystals diffract the beam into the detector

correspond to the planes of the crystals. Each crystal has a characteristic pattern of diffraction angles and the corresponding intensity of the diffracted beam. Once the beam is separated, the scatter, also called a diffraction pattern, indicates the sample's crystalline structure.

Thanks to the sub-atomic precision of both detection methods, it is possible to accurately ascertain the elemental composition, crystallographic structure, and various interaction combinations as distinct signatures within the samples. This facilitates highly accurate identification of nanoparticle tracers at the sub-atomic or quantum level. The results from nanoparticle tracer detection generated a comprehensive long-term dataset regarding nanoparticle tracer recovery in both oil and water phases, along with flow profile information for each stage. When combined with pressure diagnostics and geomechanics integration, this data enabled the most precise completion optimization workflows for the D4H well.

Figure 7 illustrates the nanoparticle tracer recovery for each of the 63 stages. The upper plot shows the recovery of nanoparticle tracers in the oil phase (or oil tracers), averaged across the first 5 samples and the last 5 samples. The lower plot displays the recovery of nanoparticle tracers in the water phase (or water tracers), also averaged for the first 5 samples and the last 5 samples. All nanoparticle tracers were detected in parts per billion (ppb) for each oil and water sample, reflecting the flow profile for each stage.

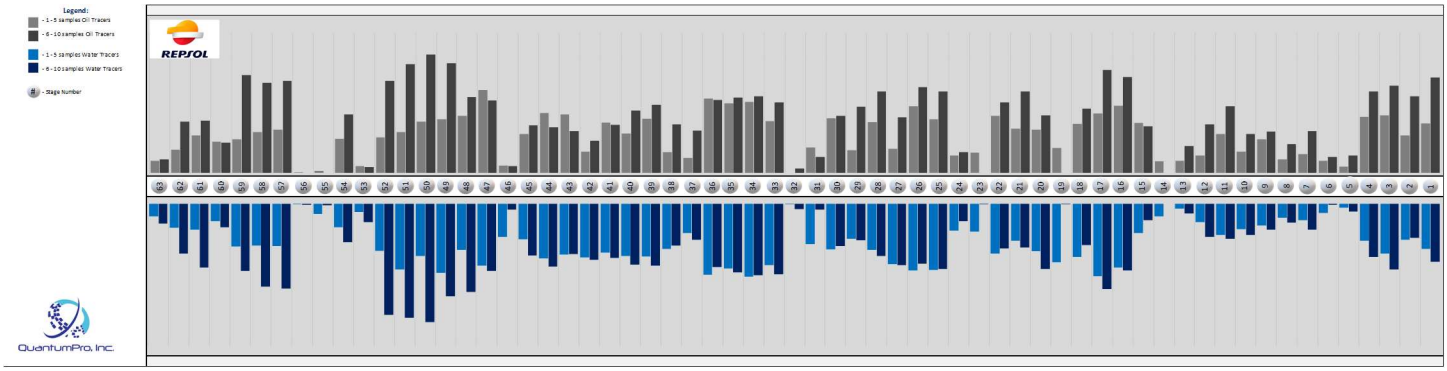

Fig. 7 – Ultrahigh-resolution nanoparticle tracer recovery along the horizontal lateral of the D4H well. The gray colors indicate oil tracers and blue colors are water tracers. The first 5 samples in each group are shown in the lighter color and the last 5 samples are the darker color.

Subsurface Nanoparticle Tracer Results Integration and Fault Evaluation

Stage-Level Production Mapping from Nanoparticle Tracer Recovery Results

The recovery of nanoparticle tracers from the D4H well began on Sept 18, 2023, alongside production and flowback activities. Fluid samples were collected from the flowline at the wellhead on Sept 18, Oct 2, Oct 16, Dec 4, Dec 31, Jan 30, 2024, and Mar 4. Figure 8 presents the results of the nanoparticle tracer recovery analysis conducted for each frac stage. By weighing the production rate from each stage by its corresponding nanoparticle tracer recovery concentration, the contributions to the stage-level production rate can be derived from the nanoparticle tracer recovery data, as illustrated in Figure 9.

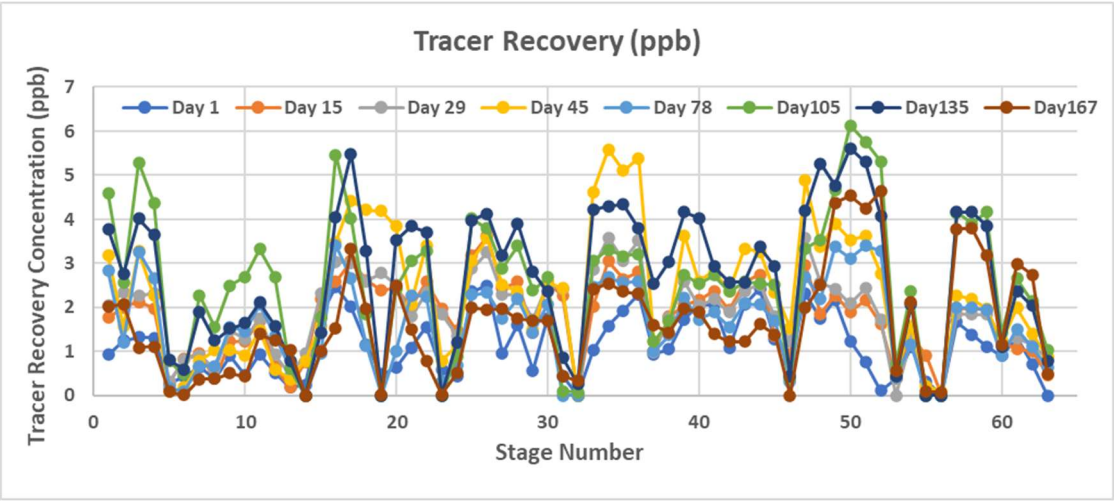

Fig. 8 – Stage-by-stage nanoparticle tracer recovery concentration from samples collected on various days

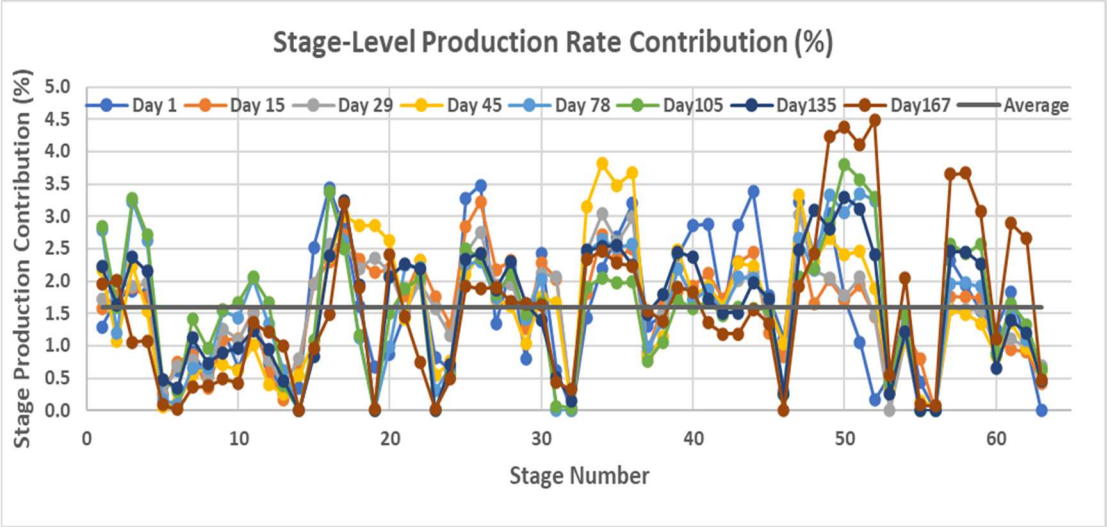

Fig. 9 – Stage-level production rate obtained from the nanoparticle tracer recovery results

Implications on Stage-Level Completion Quality (CQ) and Reservoir Quality (RQ)

Understanding the granular stage-level completion quality (CQ) and reservoir quality (RQ) is crucial for maximizing production and performance across each foot of horizontal lateral and post-frac-stage-level flow diagnostics, thus improving the reservoir stimulated volume (Mayerhofer et al. 2010). CQ refers to an engineering evaluation of the factors that influence the effectiveness of hydraulic fracture treatments. This includes the ability to initiate and establish an induced fracture network, the extent of reservoir contact made by the newly created fractures, the level of connectivity to the existing natural fracture system, and the stimulated reservoir's capacity to deliver gas or oil to the well. In contrast, RQ encompasses a geologic, engineering, and economic assessment of a resource, its reserves, and their producibility. RQ includes factors such as the volume of oil or gas in place, total organic content (TOC), thermal maturity, effective porosity, fluid saturations (oil, gas, and water), reservoir thickness, and intrinsic permeability.

By analyzing the well-established production rate over time and the stage-by-stage contributions to production (as illustrated in Figure 9), valuable insights into stage-level production can be gained. For instance, Figure 10 displays the production data for each stage over 29 days and 167 days, alongside the average production for each stage based on the assumption that all stages perform equally. As indicated in Figure 10, certain stages exceed the average production, while others fall below it. The variations in stage-level production performance may be attributed to differences in completion quality (CQ) and reservoir quality (RQ).

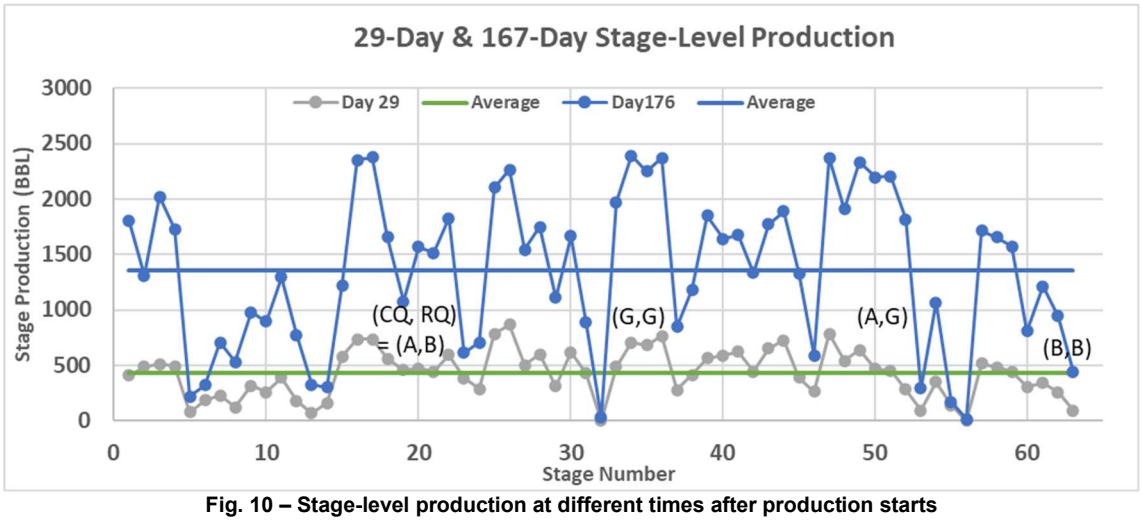

Fig. 10 – Stage-level production at different times after production starts

Monitoring and measuring stage-level production can provide valuable insights into the completion and reservoir qualities of each stage along the entire horizontal lateral. For this analysis, the following assumptions were made:

- Short-term production (e.g., 30-day or 29-day, in this case) is utilized as a proxy for completion quality (CQ), serving as a rough indicator of the conductivity of the proppant-packed fracture and its connection to the wellbore.
- Long-term production (e.g., 180-day or 167-day, in this case) is employed as a proxy for reservoir quality (RQ).

Using the assumptions outlined above, it is possible to categorize stages into average (A), good (G), and bad (B) completion quality or reservoir quality, as depicted in Figure 10 and Figure 11. Figure 11 clearly highlights the sections that underperformed and may need further attention. It is beneficial to use this information to identify both the "good" and "poor" sections. Stages 5 through 15 generally fall below average in terms of completion and reservoir qualities. This area is the UEF section, which is characterized by lower porosity and potentially lower permeability, and apparently more depleted. In contrast, Stages 15 through 22 are above average and correspond to the Austin Chalk section. The heel section (from Stage 50 onward) predominantly underperforms, primarily due to its location within a known fault zone, leading to significant inter-well interactions with adjacent wells.

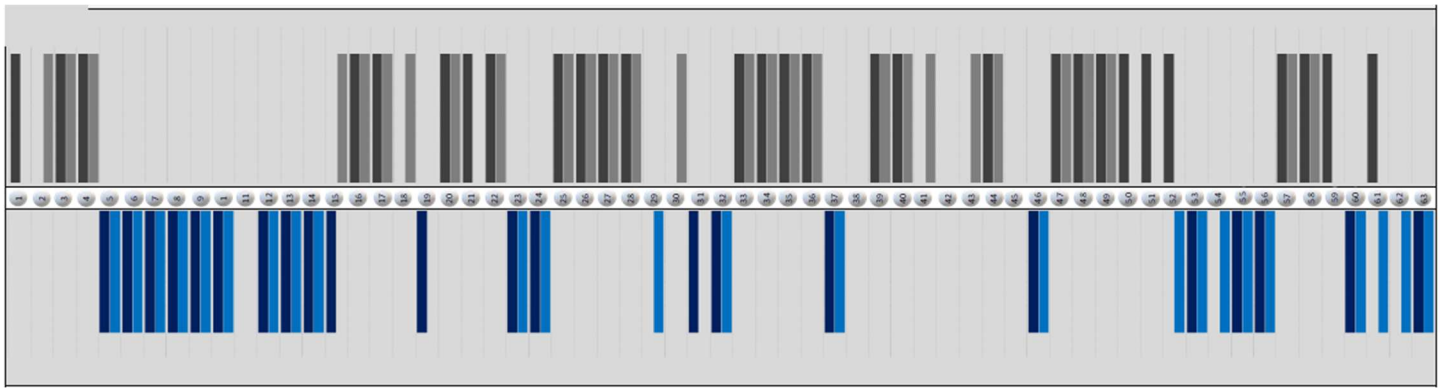

Fig. 11 – Above and below average completion quality (CQ) and reservoir quality (RQ) ranking for each of the stages. The gray colors indicate above average values and blue colors are below average values. The lighter color in each group is CQ and the darker color the RQ values (the tracers are named after the stage it was injected).

Inter-Well Interaction

An onsite sampling and monitoring campaign for nanoparticle tracers was conducted on adjacent or offset wells to investigate potential inter-well communication between the offset and traced wells. Integrating the results from the nanoparticle tracers with pressure monitoring of fracture-driven interactions (FDI) in the offset wells provided a more comprehensive understanding of geological fault integrity and inter-well communication. This data was also utilized to optimize completion designs, stage and cluster configurations, and well placement strategies, significantly improving the understanding of the reservoir and the influence of geological faults on stage-level production.

Figure12 illustrates the trajectories for the traced well and its offset wells. A sampling campaign was conducted on 4 offset wells (B3H, D3H, D2H, and D1H), while fracture-driven interaction (FDI) pressure monitoring took place on 3 offset wells (B3H, D5H, and D6H).

Table 4 presents the nanoparticle tracers that were injected into the traced well D4H and subsequently detected in the production samples from the offset wells. Notably, the results of the nanoparticle tracer monitoring and analysis reveal that:

- Significant interaction is observed in the toe section for all monitored offset wells, including well D1H, which is the farthest from the traced well D4H.
- This area primarily lies within the UEF, which is consistent with its geological characteristics of lower porosity, potentially lower permeability, and a higher elastic modulus. Additionally, stage-level production monitoring results from the traced well D4H indicated diminished completion and reservoir quality in the toe section.
- Strong interaction is also noted in the heel section, where major faults are present (Figure 12). The stage-level production data from well D4H further confirmed lower completion and reservoir quality in this area.
- Clear interaction is observed along Stages 17 and 25; Stage 17 is located within the Austin Chalk zone, while Stage 25 is situated in the LEF zone and near a fault.
- Nanoparticle tracers #49 and #50 migrated and were detected in offset wells D3H, D2H, and D1H, but not in B3H. This finding further aligns with the geological context and well spacing, as Stages 49 and 50 are quite distant from well B3H.
- The interaction with offset well B3H is the strongest, particularly from Stages 1 to 43. This makes sense, as B3H is the closest well to the traced well (refer to the well trajectory plot in Figure 12).

Offset Well #	Tracer # Detected in the Offset Well						
B3H	1-12	17 & 19	25 & 26	34-36	41-43		57
D3H	9-12	17	25 & 27			49	57
D2H	4 & 12	17	25			49 & 50	57 &58
D1H	4, 8, 9, 12	17	25	36	40	49 & 50	57-62

Table 4 - Inter-well communication between the traced well D4H and 4 offset wells (B3H, D3H, D2H, and D1H)

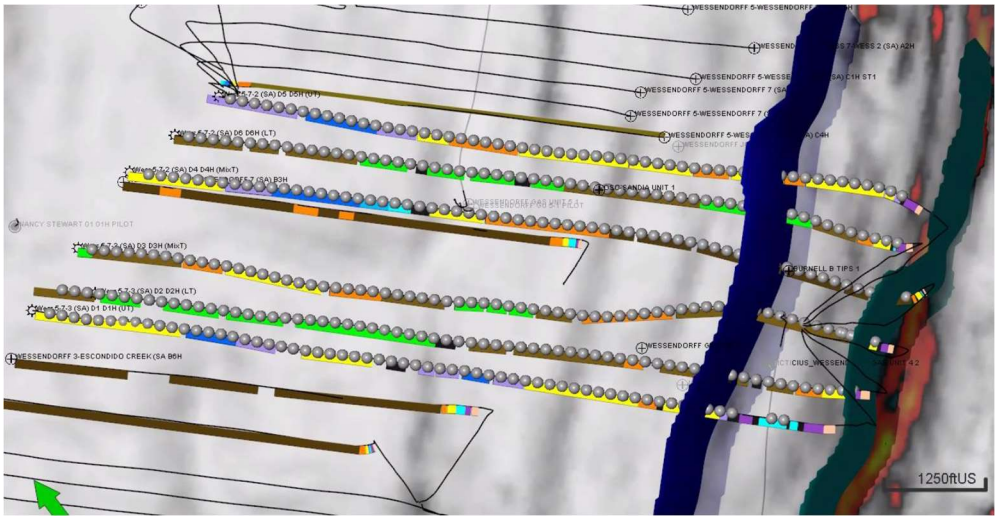

Fig. 12 – Well trajectory plot of the traced well D4H and it's adjacent wells, as well as the faults (Variance from top of Buda Formation)

The integration of nanoparticle tracer monitoring with fracture-driven interaction (FDI) pressure monitoring has enhanced an understanding of geological faults and inter-well communication. FDI pressure monitoring provides compelling evidence of pressure communication between the two wells, while tracer monitoring offers more detailed insights into how the wells are interconnected and how inter-well flow occurs. For instance, offset FDI pressure monitoring from well D4H at well B3H indicated significant interaction and a rise in casing pressure at well B3H starting from Stage 50 (Figure 13). However, only nanoparticle Tracer #57 was detected in B3H, and this detection occurred exclusively at the very start of the production flowback—specifically, in the first-day sample, with no subsequent appearances. Given that Stage 57 is relatively distant from well B3H (refer to Figure 12), it is likely that Tracer #57 reached well B3H via fluid migration through the conductive fault rather than through the propped hydraulic fracture. This conclusion aligns with the fact that Tracer #57 was observed only at the very beginning of the flowback period, suggesting that the fracture created during Stage 57 of D4H was not connected to well B3H.

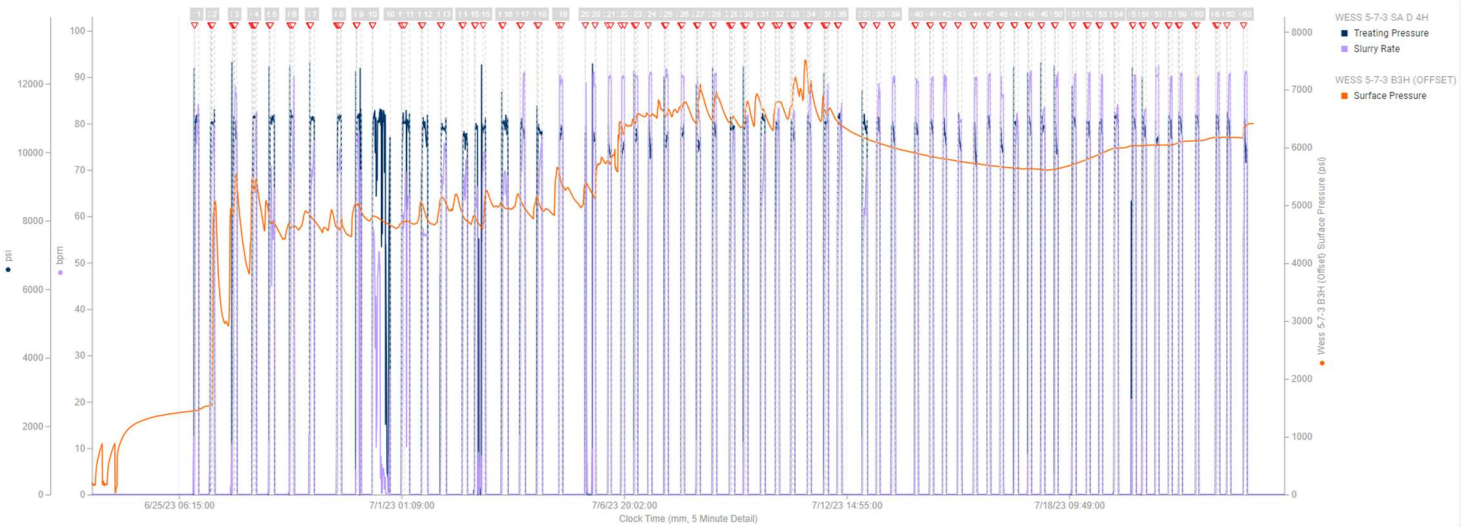

Fig. 13 – Fracture-driven interaction (FDI) test from D4H to B3H: from Stage 50 on of D4H, there is considerable interaction and casing pressure increase in well B3H

Fault Evaluation

In addition to production allocation and FDI, ultra-high-resolution nanoparticle tracers were expected to detect geological faults and other subsurface features that could influence the subsurface flow of hydrocarbons, as shown in Figure 14. By tracking the movement of nanoparticle tracers, engineers could identify areas where fluids might be leaking or bypassing the intended production zones. This data could then be used to adjust the fracturing and completion strategy, specifically the placement of stages, to enhance production efficiency, reduce capital expenditures (CAPEX), and mitigate environmental risks. Furthermore, as previously mentioned, the team was also monitoring the closed casing pressure in the offset wells. This enabled engineers to cross-check information and identify patterns related to FDI and the nanoparticle tracer's cross flow. Whenever a FDI was detected, a nanoparticle tracer response was expected, either in early or late samples. However, since pressure tends to dissipate rapidly across faults, any increase in pressure might be very subtle or short-lived, serving as a "frac corridor" through the fault.

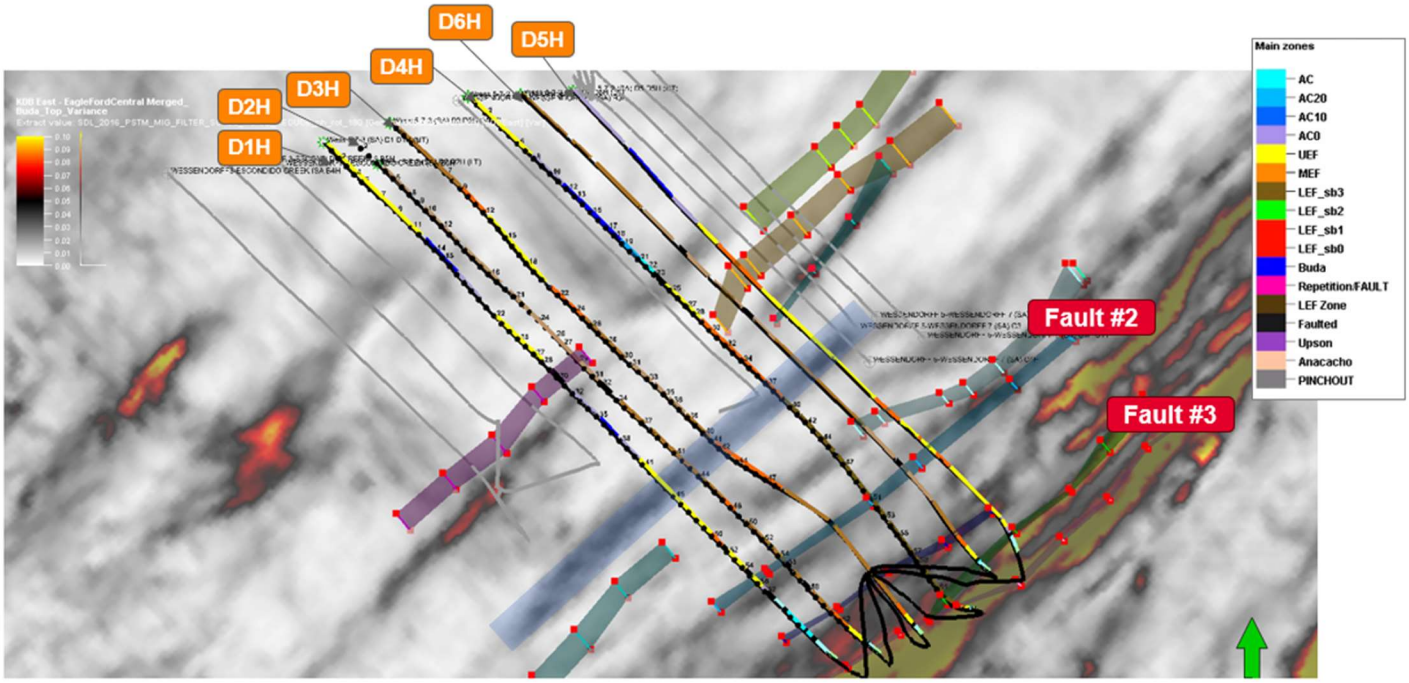

Fig. 14 – Main geological faults studied identified in seismic and geosteering

It remains unclear whether production performance will be affected if stages cross the geological faults due to the imprecision in locating the faults and the damaged interval. However, there is enhanced nanoparticle tracer recovery in the treatment well near the faults (Figure 15), possibly due to more natural and interconnected fractures and a stronger connection between the fracture and the reservoir.

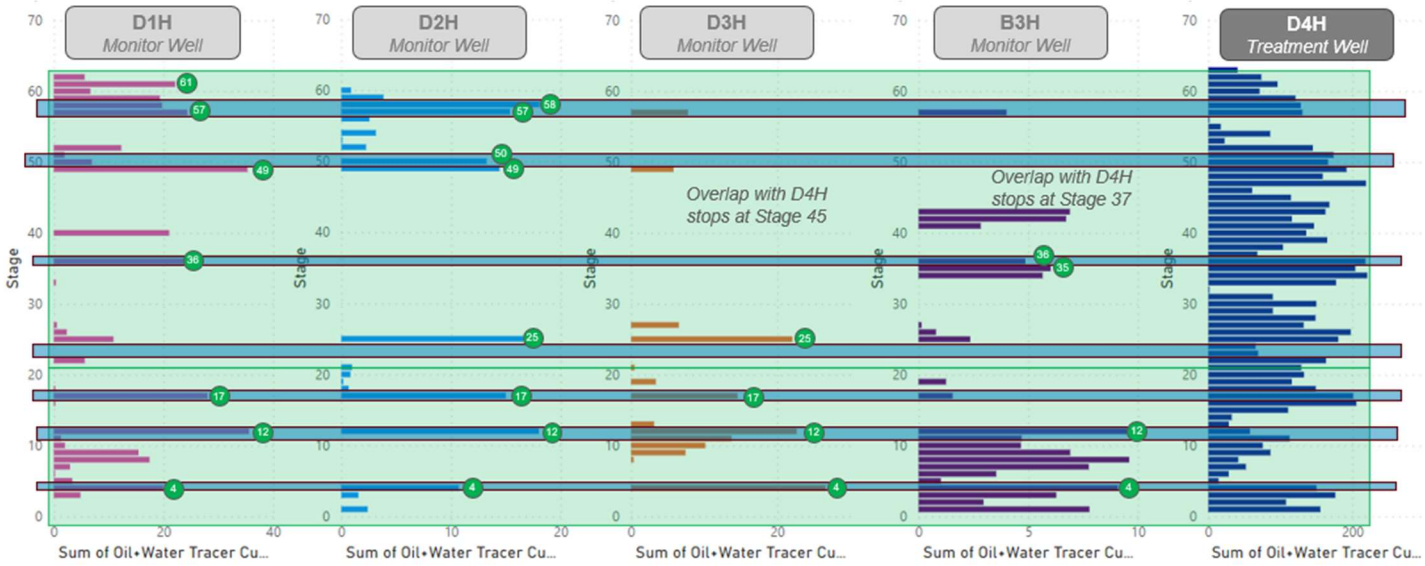

Fig. 15 – Cumulative tracer recovery in monitoring and offset wells

Another significant observation is the detection of nanoparticle tracers from zones near faults in the treated well, D4H, within the monitoring wells. This may indicate the presence of a geological feature or communication among the monitoring wells. Additionally, the depletion observed during the pre-frac pressure gradient appears to be closely related to the higher nanoparticle tracer concentration near the well's toe section.

The wells to the east of D4H were not produced, resulting in nanoparticle tracers predominantly covering the west side of the pad. Consequently, offset pressure monitoring was mainly observed towards the east of the pad. Nonetheless, certain lineaments of nanoparticle tracers and the rate of fracture propagation were noted in the vicinity of interpreted faults (identified from seismic data or geosteering), reinforcing the nanoparticle tracer findings. Additionally, some extra lineaments did not correlate with known geological features, suggesting the presence of sub-seismic features or related fracture propagation.

Conclusions

This paper presents an effort by one operator involving 1 traced well and 4 offset wells in the Eagle Ford Basin. A novel, cost-effective ultra-high-resolution nanoparticle tracer played a crucial role in generating valuable data that facilitated a comprehensive understanding of the reservoir, geological faults, and the optimization of stimulation efforts at the stage level. Additionally, multi-well studies furthered insight into inter-well communication, the characterization of fracture-driven interactions, and the optimization of well spacing.

State-of-the-art, ultra-high-resolution nanoparticle tracers were incorporated into each stage during completion to enable flow profile mapping and fault assessment. Furthermore, a sampling campaign was launched for adjacent wells to explore potential communication between the offset and traced wells. The integration of nanoparticle tracer data with pressure monitoring from offset wells enhanced the approach to developing the target reservoir and provided a critical performance flow profile for the entire development. This information was also utilized to optimize completion designs, stage configurations, and well placement strategies, significantly improving the understanding of the reservoir and the impact of geological faults on stage-level production.

The paper concludes that the pad might have been overstimulated, by giving insights about completion or reservoir issues. The nanoparticle tracer data revealed that most of the stages were performing better from the lower portion of the target zone, indicating poor vertical coverage and suboptimal fracture geometry, maybe because geomechanical limitations for fracture propagation, early time (completion related) and near to expected later time (reservoir related). Moreover, the pressure data from the offset wells showed significant fracture-driven interactions (FDIs) between the traced and adjacent wells, some of them very quick, minutes after starting pumping, suggesting excessive fracture length and height growth. These findings imply that the well could have achieved better performance with a reduced number of stages, smaller proppant volumes, and lower pumping rates.

Based on these insights, the completion design was optimized for the subsequent wells in the same area, avoiding some stages placed across the fault with risk of reactivation and a fluid intensity study started to be carried out internally, to optimize the FDI as per the timing and volume desired. These changes will result in a more efficient stimulation of the reservoir.

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