STATE OF NEW MEXICO
DEPARTMENT OF ENERGY, MINERALS AND NATURAL RESOURCES
OIL CONSERVATION DIVISION

APPLICATION OF NOVO OIL & GAS NORTHERN DELAWARE, LLC, FOR COMPULSORY POOLING, EDDY COUNTY, NEW MEXICO

Case Nos. 21037, 21038, 21039, & 21040

CLOSING STATEMENT OF OPPONENT TITUS OIL & GAS PRODUCTION, LLC

In accordance with the hearing examiners' instructions at the hearing on February 20, 2020, Titus Oil and Gas Production, LLC hereby submits this closing statement in the above-referenced cases. In the related applications, Novo Oil & Gas Northern Delaware, LLC ("Novo") proposes a total of fourteen wells, denoted the Saturninus Fed Com 1510 wells, all of which are proposed to be drilled from the same drilling pad in the SW/4 SW/4 of Section 15. It should be noted that Novo has proposed an additional 1st Bone Spring 1-mile well which is subject to an existing Joint Operating Agreement. The addition of this well brings the total wells planned for the acreage to fifteen. For purposes of this closing statement, Titus will address its concerns with the fourteen wells in the pooling applications.

The fourteen proposed wells in the pooling applications include one 1-mile well in the 1st Bone Spring in the W/2 of Section 15 (#111H), two 2-mile wells in the 2nd Bone Spring in the W/2 of Sections 10 and 15 (##121H & 122H), two 2-mile wells in the 3rd Bone Spring in the W/2 of Sections 10 & 15 (##131H & 132H), three 2-mile wells in the Wolfcamp XY in the W/2 of Sections 10 & 15 (###211H, 212H, & 215H), three 2-mile wells in the Wolfcamp A in the W/2 of Sections 10 & 15 (##221H, 222H, & 225H) and three 2-mile wells in the Wolfcamp B in the W/2 of Sections 10 & 15 (##231H, 232H, 235H). As explained below, Novo's combined proposals will result in unnecessary over-development, thereby causing economic loss, waste, and augmentation of risks arising from drilling an excessive number of wells. *See* NMSA 1978, § 70-2-17(B); *Cont'l Oil Co. v. Oil Conservation Comm'n*, 1962-NMSC-062, ¶ 11, 70 N.M. 310 ("[T]he prevention of waste is . . . paramount[.]"). Novo's applications should therefore be denied.

The issues discussed herein pertain to eight of the Saturninus Fed Com 1510 wells proposed by Novo, those proposed to be drilled in the 3rd Bone Spring, the Wolfcamp XY, and the Wolfcamp A, including the #131H (Case No. 21038), #132H (Case No. 21039), and ## 211H, 212H, 215H, 221H, 222H, and 225H (Case No. 21040). Novo proposes to drill these eight wells per half-section in the 3rd Bone Spring, Wolfcamp XY, and Wolfcamp A, which together constitute a single flow unit ("3BS/UWC Flow Unit"). *See* Titus's Exhibit No. 5; *see also* Tr. 100:9-12.

In the first half of 2018, XTO executed a similar project. XTO drilled eight wells per half-section 1.5 miles to the east, where the Wolfcamp net pay is thicker, with suspect results. XTO's wells are the Remuda North 25 State 101H, 103H, 121-124H, 902H, and 904H in Section 24 (W2) and 25 (NW4), T23S-R29E, Eddy County, New Mexico ("XTO Wells"). These wells have all been online with 12-14 months of public production data. The spacing for the XTO Wells consists of four wells horizontally spaced approximately 660 feet apart and an additional four wells directly below each of the first four wells, with vertical spacing that ranges from 262 feet to 316 feet. Titus's Exhibit No. 3.

Novo is proposing to repeat this spacing test, which by our reserve report and industry standards, was a failure. Titus's reserve report shows these wells to initially, for the first couple of months, produce at strong rates around 1000 barrels of oil per day ("bopd"), but quickly fall below industry success standards. Titus's report shows an eight-well average estimated ultimate recovery ("EUR") of 67 bbl-oil/lateral-ft, with the median also being 67 bbl-oil/lateral-ft, the P10 being 48 bbl-oil/lateral-ft, and the P90 being 90 bbl-oil/lateral-ft. Titus's Exhibit No. 4. These are not results that the industry would tout as successful. *See, e.g.*, WPX Energy, Year-End 2019 Earnings Call at Slide 6 (Feb. 27, 2020) ("Delaware Up-spacing Driving Better Performance in 2020"), *available at* https://drqwt4839jnig.cloudfront.net/media/1588/wpx-energy-year-end-2019-slide-deck-final.pdf. Novo's proposal to drill under a similar spacing plan will result in waste and impairment of correlative rights. *See* NMSA 1978, § 70-2-11 (1935).

XTO is a major operator and performed this spacing test with suspect results. Novo, on the other hand, has never drilled a multi-well pad. Tr. 38:16-23. Novo has only drilled three wells, each of which was on a single-well pad. *Id.* at 39:1-2. Nonetheless, Novo proposes to drill 15 wells from a single pad, with tighter spacing than that used by XTO. *See* Titus's Exhibit No. 5; *see also* Tr. 38:1-12.

As noted, of particular concern is the spacing for the wells proposed in the "3BS/UWC Flow Unit," that is, the Third Bone Spring sand, the Wolfcamp XY and the Wolfcamp A. *See* Titus's Exhibit No. 5; *see also* Tr. 148:17, 149:1. The spacing is too tight. *See, e.g.*, Rebecca Elliott, *Shares in Top Shale Driller Fall After it Discloses Well Problems*, The Wall Street Journal (Mar. 5, 2020) ("Concho Resources, Inc. disclosed disappointing output from wells drilled close together, an emerging problem in the shale drilling industry[.]), *available at* https://www.wsj.com/articles/shares-in-top-shale-driller-fall-after-it-discloses-well-problems-11564682681[1]; Jordan Blum, *Concho Aims to Right the Ship After Disastrous Previous Results,* Houston Chronicle (Oct. 30, 2019), *available at* https://www.msn.com/en-us/news/us/concho-

[1] A pdf of this article is attached hereto, as it can only be accessed online with a subscription.

aims-to-right-the-ship-after-disastrous-previous-results/ar-AAJzPLE (stating that Concho's CEO emphasized, "Concho is spacing its wells farther apart and not risking having the wells interfere with each other or even collapse into one another.").

For example, in one modeling study, a simulation of child wells spaced 1,320 feet had only 5% less cumulative oil production as compared to the parent well over 5 years. Trent Jacobs, Frac Hits Reveal Well Spacing May Be Too Tight, Completion Volumes Too Large, Journal of Petroleum Technology at 37 (Nov. 2017) ("The clock is running for shale producers to figure out how to mitigate the implications of this well-to-well interference issue before they drill too many wells too close together."), *available at* https://www.slb.com/-/media/files/stimulation/industry-article/201711-jpt-frac-hits-tight-spacing-large-completion-volumes. However, child wells spaced 660 feet resulted in 24% less production over the same span. *Id.*

Here, Novo proposes eight wells in the "3BS/UWC Flow Unit," which implies an average flow unit horizontal spacing of approximately 283 feet (2,640 feet minus 330 feet on either lease line, divided by seven slots between the eight wells). This horizontal spacing is too tight and will result in suboptimal production and waste.

Moreover, Novo has compounded the detrimental impacts of its proposed horizontal spacing by proposing vertical spacing that ranges from 150 feet, for two wells in the same vertical plane, to approximately 175 feet for wells that are not in the same vertical plane. *See* Titus's Exhibit No. 5. Novo's proposed vertical spacing of these wells is too tight because the target intervals are all within the same flow unit, the 3BS/UWC Flow Unit, and industry has recognized the depletion and interference issues associated with this practice. *See, e.g.*, Shin, Do et al., Optimizing Vertical and Lateral Spacing of Horizontal Wells in Permian Basin Stacked

Bench Developments, Proceedings of the 5th Unconventional Resources Technology Conference (2017)[2], *available at* http://mr.crossref.org/iPage?doi=10.15530%2Furtec-2017-2669025. Indeed, Novo recognized the significance of this issue at the hearing. *See* Tr. 98:19-99:15. Novo's geologist explained, "[I]t's about making sure you don't have too many wells directly on top of each other so they are competing. You want them to be staggered and vertically removed." *Id.* at 106:9-11; *see id.* at 99:7-15 (stating that Novo was considering changing the vertical spacing for the wells in the 3BS/UWC Flow Unit.); *see also id.* at 147:16-148:11 (explaining why Novo's proposals are similar to the XTO Wells and how Novo's wells could be competing for resources).

In addition, the target interval for the 221H, 222H, and 225H (Wolfcamp A) wells is very thin compared to the same zone targeted by XTO in Remuda Basin, primarily due to an approximately 40-feet thick tight carbonate debris flow cutting out some of the reservoir. . *See* Exhibit 2 (Enlarged)[3]; Tr. 143:20-144:6, 170:12-171:5. As is evident from Exhibit 2 (Enlarged), the target interval is approximately 25-feet thick and characterized by high porosity. *See* Novo Exhibit 25; Tr. 86:18-20, 105:23-106:4. The target is bound below by the aforementioned carbonate that is non-reservoir and likely a frac barrier. This is thin compared to proven Wolfcamp A shale horizontal targets in the area. Considering that when hydraulically fracturing a well, operators expect to get fracture growth upwards, as well as downwards, to link up as many carrier beds as possible, this target exhibits limited upside by virtue of being located directly above a frac barrier. Thus, industry geomechanical models would suggest the frac to grow predominantly in the upward direction, further communicating with the other wells

[2] A pdf of this article is attached hereto, as it can only be accessed online with a subscription.
[3] Exhibit 2 (Enlarged), which was requested by the Hearing Examiner, is submitted concurrently with this Closing Statement. *See* Tr. 173:16-174:7.

proposed in this flow unit, contrary to the desired stimulation by Novo. *See* Tr. 105:9-16, 107:7-15; *see also id.* at 99:7-15 (stating that Novo was considering changing the vertical spacing for the wells in the 3BS/UWC Flow Unit.); *id.* at 106:9-11 (Novo's geologist explained, "[I]t's about making sure you don't have too many wells directly on top of each other so they are competing. You want them to be staggered and vertically removed."); *id.* at 147:16-148:11 (explaining why Novo's proposals are similar to the XTO Wells and how Novo's wells could be competing for resources). These observations are also supported by the two-well cross-section, C-C', in Novo's Exhibit No. 25. The 40-feet thick carbonate that is likely a frac barrier for the 221H, 222H, and 225H is located at approx. 10,300 ft on the Teledyne 4 Gas Com 1 well. Exhibit 2 (Enlarged) reveals that XTO's Wolfcamp A shale wells (121H, 122H, 123H, and 124H) did not have to contend with carbonate debris flow removing the lower portion of the horizontal target.

Finally, Novo has underestimated each of its AFEs by including a lesser number of drilling days from spud to rig release than the number of days that will likely be required. XTO recently drilled 24 1.5-mile laterals in Remuda Basin, approximately 1.5 to 2.5 miles to the east of Novo's proposed development, across six pads. XTO's fastest drilling performance across these six pads was 28.5 days per well, the average was 32.8 days per well, and the median was 32.6 days per well. *See* Titus's Exhibit No. 7. These were 1.5-mile laterals, whereas Novo is contemplating the drilling of 15 2-mile laterals. Novo has never embarked upon an operation of this magnitude, whereas XTO has, yet averaged 32.8 days per 1.5 mile lateral well across a large 24 well dataset. This illustrates that Novo has significantly underestimated the number of drilling days that would be required and, thus, significantly underestimated drilling costs.

For all of the reasons stated herein, and in light of current industry knowledge and standards, the wells proposed in the 3BS/UWC Flow Unit should be limited to four, with spacing similar to that reflected in Titus's Exhibit No. 6.

Respectfully submitted,

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CERTIFICATE OF SERVICE

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Optimizing Vertical and Lateral Spacing of Horizontal Wells in Permian Basin Stacked Bench Developments

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This paper was prepared for presentation at the Unconventional Resources Technology Conference held in Austin, Texas, USA, 24-26 July 2017.

Summary

This paper describes ways to optimize vertical and lateral spacing of horizontal wells in a stacked bench development up-front and, if necessary, adjust the development spacing based on early time Gas-Oil-Ratio (GOR) behavior, other diagnostic methods, and/or seismic inversion.

In recent years, the Permian Basin has become the leading unconventional resource play due to, among other things, the high quality of the resource and stacked-bench horizontal well developments. Maximizing recovery and profitability in a stacked-bench unconventional play is challenging because operators must optimize both the inter-bench vertical well spacing and the intra-bench lateral well spacing.

Generally, well interference can be detected by comparing well productivities, initial reservoir pressures, Stimulated Rock Volumes, and Expected Ultimate Recoveries against forecasted well performance. However, such analyses do not directly reveal whether any observed interference is due to inter-bench or intra-bench interactions. Without the ability to distinguish inter-bench interference from intra-bench interference in advance, vertical and lateral spacing optimization might be achieved only at the risk of over-capitalizing a development.

This paper presents a case study in which an analysis of GOR behavior was coupled with other analyses to determine the source of interference. Stand-alone (i.e., widely-spaced) wells in each bench were found to display unique GOR characteristics. When horizontal wells in different benches interfered with one another, however, the GOR trends observed in the wells were synchronized.

Wells with synchronized GORs exhibited substantial departure (better or worse) from expected performance, thereby confirming the hypothesis that they were interfering. Among wells that had synchronized GORs, in some cases, production from one well appeared to have been captured by another well, whereas in other cases, productivity of both wells were affected.

It was found that the contrast in the elastic properties of the stacked benches, which was discerned from the inversion of seismic data, played a key role in the vertical interference between wells. When stacked benches have similar elastic properties, much stronger interference was observed than when the elastic properties were dissimilar. As demonstrated by previous laboratory experiments (Thiercelen et al., 1987), mineback studies (Warpinski et al., 1981; Warpinski et al., 1987), and modeling (Thiercelen et al., 1987; Barree et al.; 1998; Smith et al., 2001; Zhang et al., 2007), a large contrast in the elastic properties between benches appears to create flow barriers at the interface.

EXHIBIT A

Introduction

Due to the richness of resources, improvements in hydraulic fracturing technologies, and utilization of existing facilities, a number of Permian Basin stacked bench plays are profitable to develop, even in today's oil price environment. However, achieving profitability while maximizing recoverable reserves from such stacked reservoirs is more challenging than in a single bench development. This is because the vertical inter-bench well spacing needs to be optimized as well as lateral intra-bench spacing. In order to optimize vertical inter-bench spacing, the drainage height of each multi-stage hydraulically fractured horizontal well needs to be accurately identified. Estimating the drainage height, however, is technically difficult because it involves accurately modeling hydraulic fracture propagation, proppant transport, and effects of geologic discontinuities.

Well spacing is ultimately a question of economics and reserves. Wells should be drilled such that the entire section can be drained in a timely manner, yet far enough apart to avoid over-capitalization (Lalehrokh et al., 2014). Therefore, a denser well spacing may be more appropriate at a high oil price environment, whereas a wider spacing may be necessary to maximize Net-Present-Value (NPV) and Rate-Of-Return (ROR) in a low price environment.

The factors controlling interference between wells in unconventional reservoirs appear not to be well established. At the moment, a trial-analyze-modify approach appears to be the most common development strategy in the industry. In other words, a number of wells are drilled in an area at a pre-determined spacing, then based on the outcome, future well spacing is adjusted. For example, Pettegrew et al. (2016) compared the degree of interference of various Delaware Basin Wolfcamp well spacing using Wellhead Pressure vs. Cumulative Oil plots, shut-in tests, and microseismic interpretations. Then forecasts were generated for a range of well spacings using 3D sector models. Such trial-analyze-modify method is manageable for a single bench development, but in a stacked bench development, the level of complexity and costs increase exponentially. In fact, it may become difficult to identify whether the source of interference is due to intra-bench or inter-bench interaction.

Advancements have been made in the industry in understanding and predicting the impact of well interference. Some of the methods include: Rate-Transient-Analysis (RTA) (Lawal et al., 2013; Yadav et al., 2017), shut-in and drawdown tests (Awada et al., 2015; Scott et al., 2015), microseismic (Fisher et al., 2011; Friedrich et al., 2013), tiltmeters (Wright et al., 1998), frac models (Barree et al.; 1998; Zhang et al., 2007), and frac hits. Individually, they provide an insight into well behaviors, but rarely provide a complete picture of interaction between wells. Also, there is no accurate way to measure the drainage height of a hydraulically fractured horizontal well, which is crucial for determining inter-bench well spacing. In order to economically develop stacked benches, there is clearly a need for understanding physical drivers that control drainage height, so that inter-bench well interference can be predicted in advance.

This paper presents an integrated reservoir engineering analysis method that uses three key production plots to understand the interaction and interference of stacked bench horizontal wells. In addition, a use of seismic inversion derived elastic properties for identifying potential flow barriers and drainage height is demonstrated.

Theory / Backgrounds - Integrated Reservoir Engineering Analysis for Well Interference

If a group of wells in stacked benches is suspected of interfering with one another, the following needs to be considered to determine the source of well interference.

1) How much productivity degradation has occurred compared to a standalone well in a geologically similar area?
2) Are the initial conditions (P_i, R_{si}, etc.) of the wells similar to the standalone well?
3) Does the well have a synchronized behavior (GOR, fluid rates, etc.) with neighboring wells, including wells in adjacent benches?

The following plots have been found to be useful in answering these questions: "Pressure-Normalized-Rate (PNR) vs. Cumulative Oil" plot, "Gas-to-Oil Ratio (GOR) vs. Date" plot, and "Initial Reservoir Pressure (P_i) Comparison" plot. Each diagnostic plot reveals an insight into the interaction between multiple wells in a stacked bench. By combining these insights, the source of well interference can be identified. In this section, the theory behind each diagnostic plot is reviewed and the collection together will yield a clearer picture of the interactions between the stacked bench wells used in this case study.

Pressure Normalized Oil Rate (PNR) Behavior of Interfering Wells

The Pressure Normalized Oil Rate (PNR) vs. Cumulative Oil plot can be used to identify underperforming wells. It is similar to the Oil Rate vs. Cumulative Oil plot, except the Oil Rate is normalized by the drawdown pressure, as expressed below.

$$PNR = \frac{q_{oil}}{P_i - P_{wf}} \quad (1)$$

Normalizing the oil rate by the drawdown pressure dampens the effects of operational variations between wells. In addition, horizontal wells with different lateral lengths can be compared by normalizing the PNR and Cumulative Oil by lateral length of individual wells. Due to the heel-toe interaction in a horizontal well (Jha, 2015), such normalization can skew the early time productivity in favor of shorter horizontal wells. However, comparing long term trends gives an accurate comparison of well performance and drainage volume.

Figure 1 shows a field example where five horizontal wells were drilled in the same bench in a geologically similar area. The **blue** well is a standalone, whereas the **red** wells each have an offset in the bench above. The **green** wells, on the other hand, offset each other in a tight intra-bench spacing, and they each have an offset in the bench above. Given that the geology and stimulation designs are similar between these wells, any degradation in productivity is likely due to well interference.

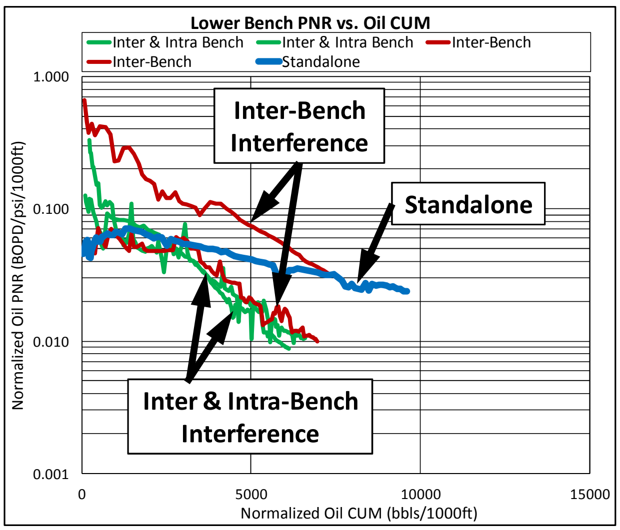


Figure 1: Pressure-Normalized-Rate (PNR) vs. Cumulative Oil normalized to 1000 ft of lateral length. Differentiating inter-bench and intra-bench interference can be difficult.

Since the **red** wells have degraded PNR when compared to the **blue** standalone well, it appears that the red wells have been affected by inter-bench interference. The **green** wells show even more PNR degradation, which appears to be due to both inter-bench and intra-bench interference.

However, it is often difficult to narrow down the source of interference using this plot alone. For example, the **green** wells, which should be experiencing both inter-bench and intra-bench interference, have similar productivity as one of the **red** wells, which should only be under inter-bench interference. Therefore, once productivity degradation is identified, additional analysis is necessary to narrow down the source of interference.

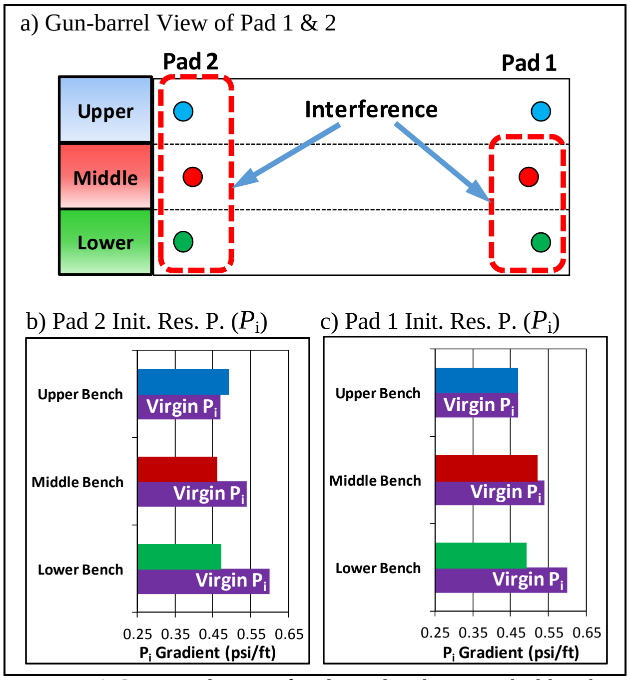


Figure 2: a) Gun Barrel View of Pad 1 and Pad 2 in stacked benches. b) Pad 2 initial reservoir pressures (P_i) showing all three benches interfering. c) Pad 1 initial reservoir pressures (P_i) showing **Middle** & **Lower** benches interfering.

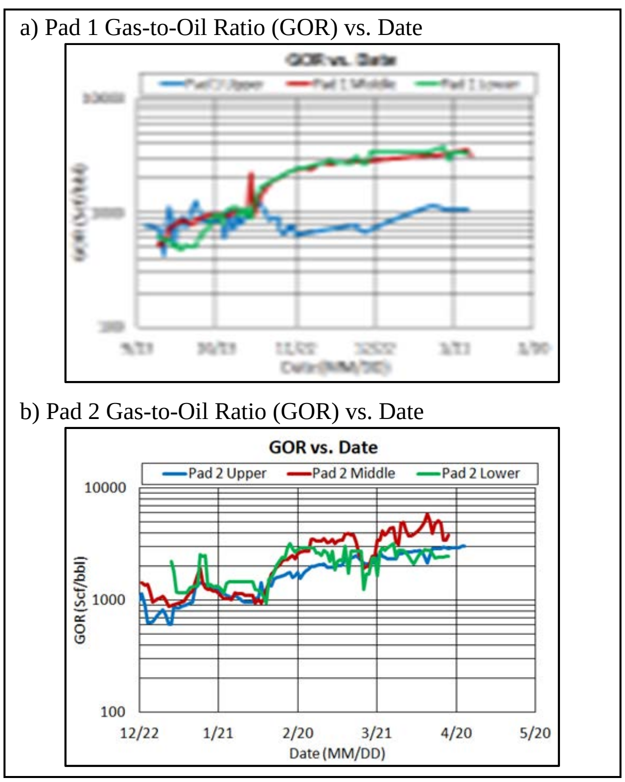


Figure 3: a) Synchronization of Gas-to-Oil Ratio trends & magnitudes between interfering benches (**Middle** & **Lower**). b) Synchronization of GOR trends in three interfering benches

Initial Reservoir Pressures of Interfering Wells

The initial reservoir pressure measurement method provided by Jones et al. (2014) can be used to gain an insight into well interference. This method is based on empirical observations that in an hourly flowback data, the flattening of bottom-hole-pressure (P_{wf}) prior to first measureable hydrocarbon production closely resembles initial reservoir pressure.

As shown in Figure 2, an artifact of well interference is that for interfering wells, initial reservoir pressures estimated from hourly flowback are noticeably different from their virgin reservoir pressures. In Pad 1 (Figure 2c), the initial reservoir pressures of the Middle and Lower benches are lower than their respective virgin reservoir pressures. The initial reservoir pressure of the Upper bench, however, matched its virgin reservoir pressure. This indicates that the Middle and Lower benches are interfering, but the Upper bench is not.

On the other hand, in Pad 2 (Figure 2b), estimated initial reservoir pressures in all three benches are noticeably different than their respective virgin reservoir pressures. Unlike the Middle and Lower benches, the initial reservoir pressure of the Upper bench exceeded its virgin reservoir pressure. This appears to be due to the fact that the higher reservoir pressure of the Middle bench is affecting the Upper bench well.

Gas-to-Oil-Ratio (GOR) Behavior of Interfering Wells

Another artifact of interference is the synchronization of GOR trends among interfering wells. Jones (2016) provides a comprehensive review on GOR behavior of wells in unconventional reservoirs. The GOR behavior is mainly controlled by PVT properties, solution GOR at initial reservoir pressure (R_{si}), bottom-hole-pressure (P_{wf}), and the size of the drainage volume. Since these variables tend to be unique in each formation, a standalone well in each bench displays unique GOR characteristics. Therefore, if wells in stacked benches show synchronized GORs, it indicates that they are interfering. Though this technique can be used to detect intra-bench interference, the synchronization is more pronounced for inter-bench interference.

Figure 3 shows two field cases. In Pad 1, only the Middle and Lower benches are interfering. Therefore, only the Middle and Lower bench wells show synchronized GOR (Figure 3a). On the other hand, in Pad 2, wells in all three benches are interfering, and their GOR trends are synchronized (Figure 3b).

It was found that when interfering wells have similar P_{wf} profiles, GOR magnitudes also synchronized, but dissimilar P_{wf} profiles resulted in trend synchronization only. Since trend synchronization occurs even when P_{wf} profiles are dissimilar, gas migration appears to be taking place between benches when they interfere.

Theory / Backgrounds - Elastic Property Contrast as a Flow Barrier

The production analysis method presented above can be used to identify inter-bench well interference for the wells that have already been drilled. In order to be able to predict inter-bench interference, physical variables controlling the drainage height of a horizontal well need to be understood. These variables are: hydraulic fracture height, proppant transport height, and the effects of geologic discontinuities, such as beddings, joints, and faults. Modern frac models can be used to understand the first two variables, but they typically do not capture the effects of geologic discontinuities (Barree et al., 1998). In this section, effects of geologic discontinuities on hydraulic fracturing propagation and proppant transport are reviewed. In addition, their application in stacked-bench development is explored.

Elastic Property Contrast Is Not a Frac Barrier

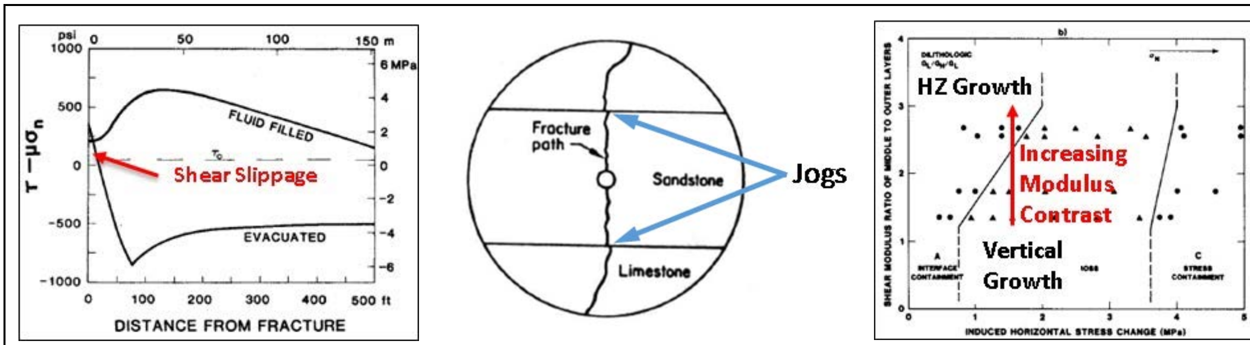
Analytical modeling by Simonson (1978) showed that when a fracture propagates from a high elastic modulus material to a lower elastic modulus material, it may be arrested at the interface because the stress intensity would approach zero. However, mineback (Fisher & Warpinski, 2012, Warpinski papers) and laboratory experiments (Teufel & Clark, 1984; Thiercelin et. al, 1987; Warpinski et al., 1982; Daneshy, 1978, Anderson, 1981) have proven that the contrast in the elastic properties does not stop a fracture from propagating across an interface. As a matter of fact, the vertical stress profile has been determined to be the primary mechanism that controls fracture height (Warpinski et al., 1982, 1987; Fisher et al., 2012).

Interfacial Fracture Growth along the Bedding/Discontinuities

During these experiments, however, interfacial fracture growths were observed along geologic discontinuities such as, beddings, joints, and faults. Analytical and numerical modeling of fractures crossing geologic discontinuities (Barree et al., 1998; Warpinski & Teufel, 1987; Zhang et al., 2007; Gu et al., 2006; Gu et al., 2008) showed that in stacked formations, a vertical fracture propagating from one layer to another could trigger shear slippage along the interface before the fracture could be extended into the adjacent layer. In that case, the direction of the fracture would change, and propagate horizontally along the interface.

Shear slippage along the interface is triggered when its' bond strength and friction is overcome by the shear stress induced from the vertical fracture. Thus, the interfacial fracture propagation is more likely to occur when overburden, surface roughness, and bond strength between layers are small, and induced shear stress is large. In addition, if the interface is permeable, fluid invasion in the interface would reduce the normal stress acting on it, and encourage shear slippage and dilation (Barree et al., 1998; Zhang, et al, 2007).

Once a fracture begins propagating along the interface, it may still cross into the adjacent layer by initiating a pre-existing crack. However, if the bond strength between the layers is weak, or the fracture encounters a "composite-layer effect", then the fracture may be arrested at the interface (Fisher & Warpinski, 2012; Zhang et al., 2007).



a) Warpinski et al. (1987) b) Thiercelen et al. (1987) c) Teufel et al. (1984)

Figure 4: a) Extent of shear slippage along the fluid filled vs. evacuated interface from the parent fracture face based on analytical modeling (Warpinski et al. (1987) b) Laboratory experiments by Thiercelen et al. (1987) shows fracture jogs at material interface c) Laboratory experiments by Teufel et al. (1984) shows that for a given stress condition, interfacial fracture arrest is more likely to occur at a higher shear moduli contrast between layers of rock

Nolte (1987) and Warpinski et al. (1987) pointed out that due to the sheer magnitude of the depth and the overburden, such fracture arrest at the interface would not occur in most hydrocarbon reservoirs. Even so, tiltmeter mapping and seismic monitoring both showed that even in a deep reservoir where dominant fractures are vertical, a large number of horizontal secondary fractures were detected (Wright et al., 1998). These horizontal fractures appeared to be associated with bedding separation (Barree et al., 1998; Warpinski et al., 1987).

As shown in Figure 4a, analytical modeling by Warpinski et al. (1987) demonstrated that even in a deep reservoir, shear slippage of interface could occur near the fracture face, even though the main fracture had crossed the interface into the adjacent layer. Experimental and numerical simulation work carried out by Thiercelin et al. (1987) also demonstrated that even when fractures propagate across layers, they tend to jog at the interface (Figure 4b). Such jogging behavior became more pronounced as the contrast in the elastic properties between the stacked layers increased. Further evidence is provided by Teufel et al. (1984), whose experimental work showed that for a given stress condition, a greater contrast in shear modulus between the stacked layers increased the likelihood of shear slippage at the interface (Figure 4c).

This appears to be due to the fact that a greater contrast in the elastic properties of the stacked layers results in a more pronounced strain incompatibility at the interface. Therefore, during hydraulic fracturing, a greater shear stress is developed at the interface, and shear slippage would occur more readily. As Teufel et al. (1984) pointed out, the development of shear stresses along a bi-material interface of contrasting elastic properties subjected to uniaxial stress conditions is well known in the composite literature.

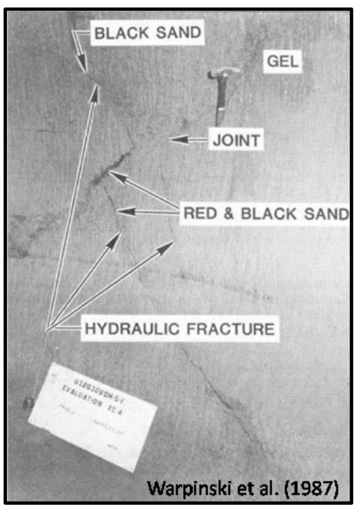


Figure 5: Mineback excavation of colored sand fracturing experiment (Warpinski et al., 1987). Screenout was observed at fracture offset.

Jogs and Offsets as Flow Barriers

The main concern with jogs and offsets is that though they may not be barriers to some of the hydraulic fracturing fluids, they could be flow barriers to the original reservoir fluids once a well is placed on production. At jogs and offsets, proppant transport may be hindered or proppant could be more readily crushed by the overburden.

Zhang et al. (2007) and Barree et al. (1998) found that the fracture widths at jogs and offsets are much narrower than the parent fracture, which could serve as a proppant transport barrier. To explore the effects of such tortuosity on proppant transport under in-situ conditions, Warpinski et al. (1981, 1987) conducted a mineback experiment, where three stages of sand frac were pumped with uniquely colored proppant for each stage (in the order of black, red, and blue). Only a small amount of black proppants were found across the joint, and a large amount of black and red proppants had filled the offset in the fracture. Therefore, it is difficult to expect production contribution above the interface, where fractures are not propped.

In a stacked bench development, such jogs and offsets could manifest themselves as flow barriers. Therefore, where a large contrast in the elastic properties exist between stacked benches, frac hits may be observed between benches, but the wells may not interfere during production.

Narrow Frac Width as Flow Barriers

Another mechanism that may create flow barriers is the narrow fracture width. Finite Element Modeling of hydraulic fractures by Smith et al. (2001) showed that a very narrow fracture width resulted in a hard shale layer with a high Young's Modulus when it was surrounded by two sand layers with a lower Young's Moduli. Therefore, proppants were not able to transport through the width restriction, thereby creating a flow barrier.

Theory / Backgrounds - Flow Barrier Identification Using Seismic Inversion

To identify flow barriers prior to development, three dimensional variations of elastic properties need to be understood. A way to achieve this is through the integration of 3D seismic data. Using a modern day, wide azimuth, long offset 3D dataset, such as the one represented by Figure 6 (courtesy of Seitel Data Ltd). To compare log and seismic data together, the seismic data needs to be transformed into the principal components of the Young's Modulus equation, expressed below (Zoback, 2010).

$$\nu_{dyn} = \frac{\left(\frac{V_P}{V_S}\right)^2 - 2}{2\left[\left(\frac{V_P}{V_S}\right)^2 - 1\right]} \quad (2)$$

$$E_{dyn} = (3V_P^2\rho - 4V_S^2\rho)(1 - 2\nu_{dyn}) \quad (3)$$

Seismic data is a measure of rock interface reflectivities. The process of pre-stack simultaneous inversion (Russell, 2014) converts reflectivities to P-wave and s-wave velocities and density volumes, which are calibrated back to well data. These products are then used to convert the seismic data to a volume of Young's Modulus. The images in Figure 6 and Figure 9 represent a vertical slice through that converted volume.

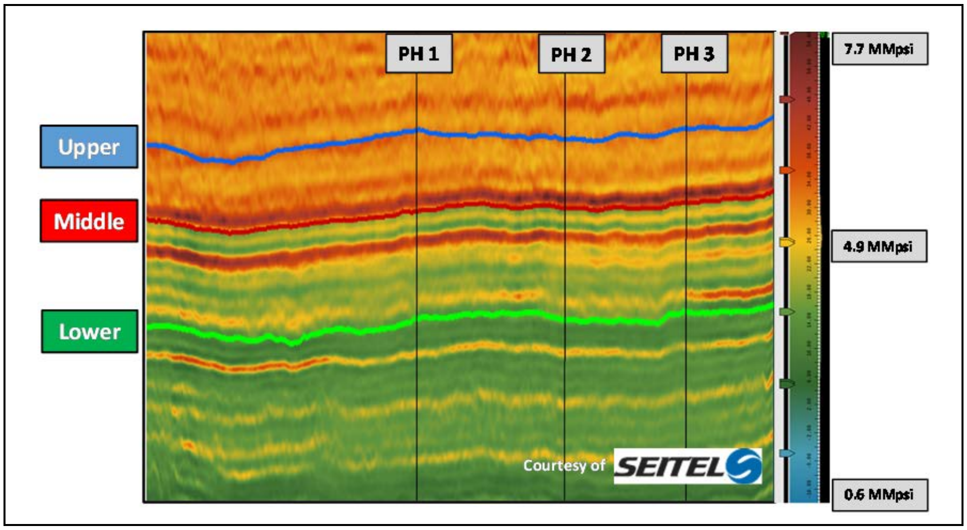


Figure 6: X-section view of 3D Young's Modulus volume generated from 3D seismic inversion. Courtesy of Seitel Data Ltd.

To understand the closeness of fit of seismic generated Young's modulus to the well data, a cross plot along with an R^2 value is shown in Figure 7, along with a curve overlay at a specific well location.

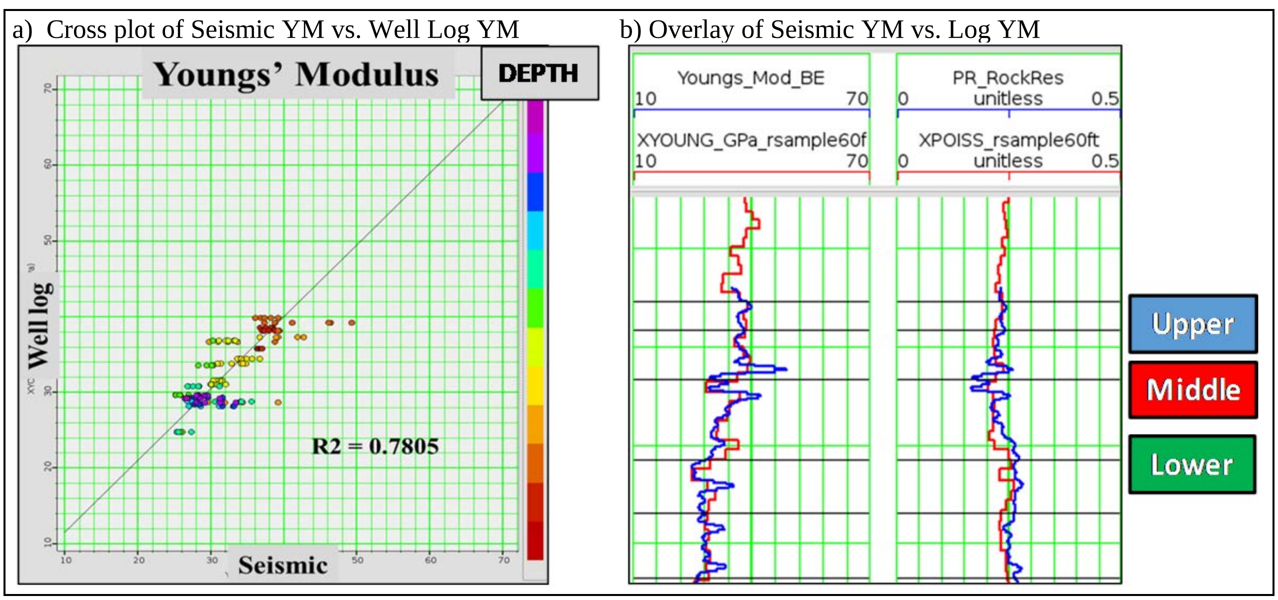


Figure 7: a) X-plot of seismic vs. well log Young's Modulus b) Overlay of Seismic Young's Modulus vs. Log Young's Modulus at a well location

Case Study

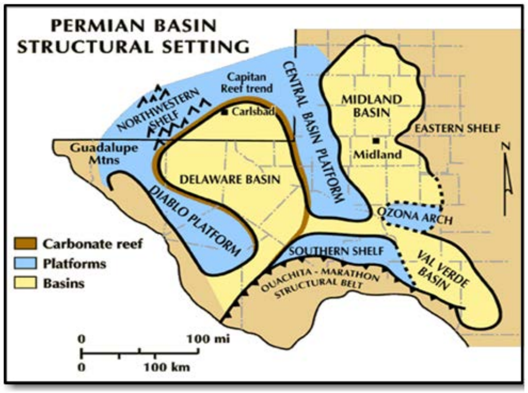


Figure 8: Overview of Permian Basin

In this case study, well interference and spacing analysis via integration of production analysis and geomechanics is demonstrated. Geologic variation is minimal in the field selected for this study, but a wide range of elastic properties exists.

To investigate the effects of inter-bench interference and the role of elastic properties, a total of two standalone pads (Pad 1 and Pad 2) were drilled in different parts of the field. Each pad contained three wells, targeting three different benches, designated as Upper, Middle, and Lower. Also, in order to investigate the combined effects of inter-bench and intra-bench interference, Pad 3 and Pad 4 were drilled in close proximity to one another. They were drilled in the same section as Pad 1, and share a similar geomechanical stratigraphy, but far enough apart that the wells in Pad 1 did not interfere with the wells in them.

For standalone and non-standalone pads, the vertical separation of the horizontal wells was approximately 200 ft. Also, most pads were zipper frac'd, and began producing nearly simultaneously. Comprehensive data collection was also conducted, including Bottom-Hole-Pressures (BHP), PVT samples, shut-in test, frac-hit monitoring, logs, microseismic, as well as modern-day seismic. The layout of the pads are shown in Figure 10 and Figure 13.

Geologic description of the field

Shown in Figure 9a is the type log of the three development benches, Upper, Middle, and Lower. They were deposited in a deep marine environment where episodic debris flows manifest themselves as interbedded carbonate layers. Since the Upper bench was deposited in a more proximal setting, the carbonate content and elastic properties are greater than the ones in the other two benches.

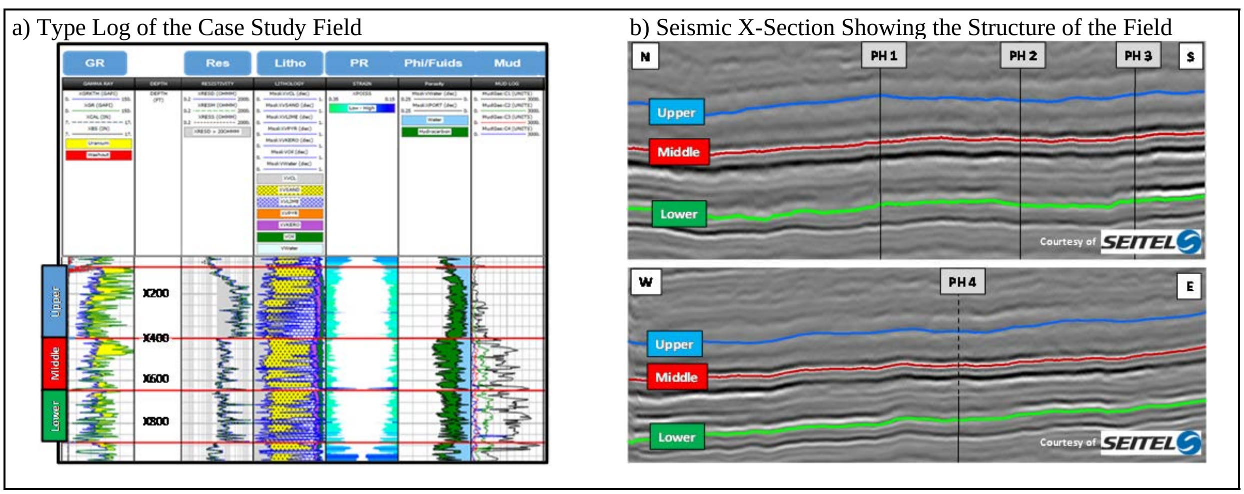


Figure 9: a) Type log of the case study field. b) Seismic structure of the field showing simple basinal structure. Courtesy of Seitel Data Ltd.

The Upper bench is approximately 300 ft thick, whereas the Middle and Lower benches are each 250 ft thick. The field is structurally simple, as shown in the seismic amplitude cross-section in Figure 9b, and each bench has a similar Original-Oil-in-Place (OOIP) across the field. Also, elastic property heterogeneity in the Middle and Lower benches is more pronounced than that in the Upper bench.

Pad 1: Inter-Bench Interference between Middle & Lower Benches

Pad 1 was drilled in the eastern part of the field where the Young's Modulus of the upper bench is significantly higher (~5.8 MMpsi) than the Middle and Lower benches (less than 4.7 MMpsi), as shown in Figure 10b.

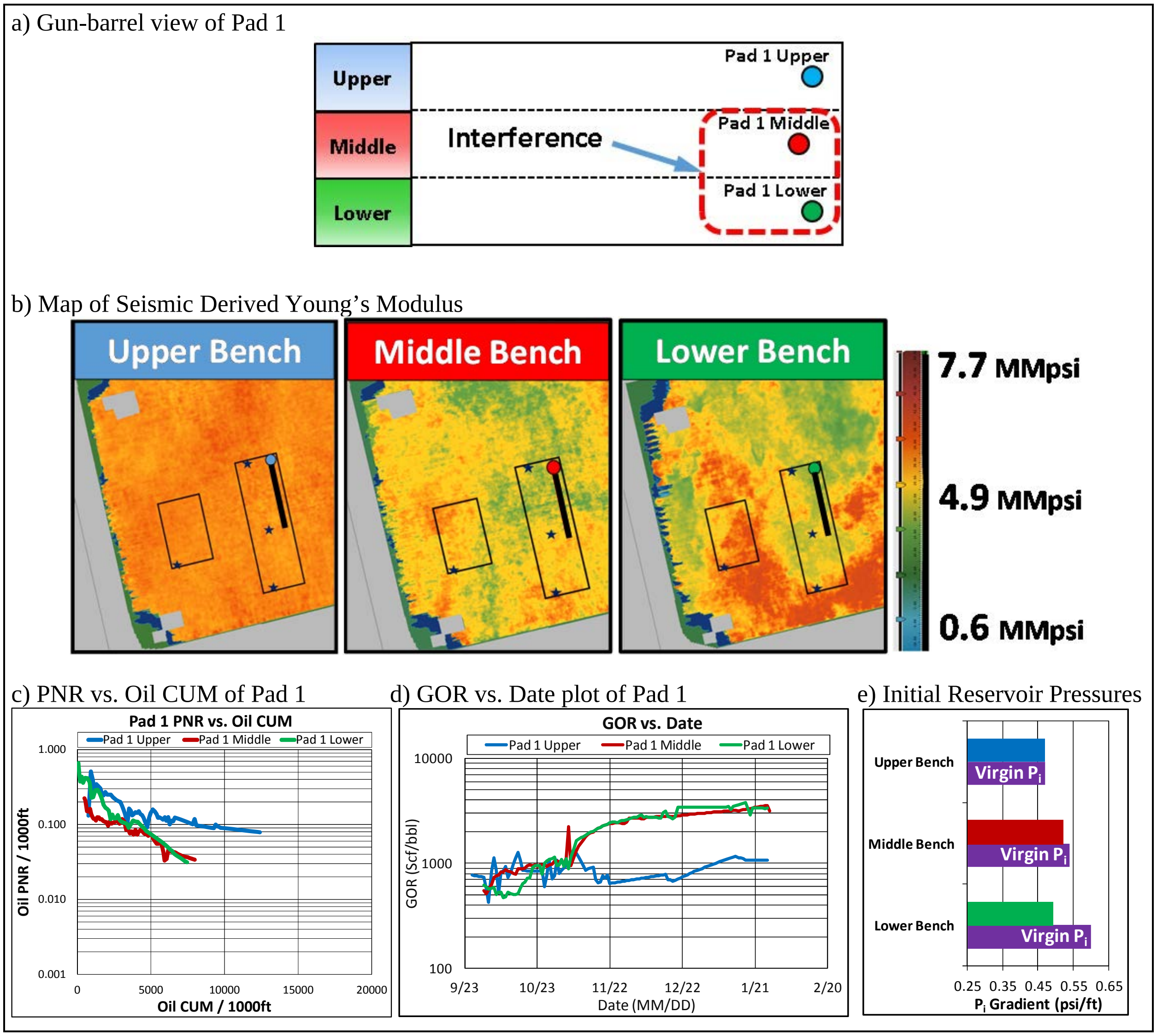


Figure 10: a) Gun-barrel view of Pad 1. b) Map of seismic inversion derived Young's Modulus. c) Pad 1 Pressure Normalized Rate (PNR) vs. Cumulative Oil normalized to 1000ft of lateral length. d) GOR vs. Date for Pad 1 wells. Middle and Lower bench wells are interfering and have synchronized GOR trends. e) Initial Reservoir Pressures of Pad 1wells. Middle and Lower bench wells are interfering, and are showing lower than expected initial reservoir pressures.

The PNR vs. Oil CUM plot (Figure 10c) shows that the Pad 1 Upper well has significantly outperformed the Middle and Lower wells. The Upper bench was expected to outperform due to its' higher Young's Modulus, but since the OOIP is higher in the Middle and Lower benches, the degree of divergence in well performance was not anticipated. From Figure 10d, it is clear that the GOR trends of the Middle and Lower wells have synchronized. On the other hand, the GOR trend of the Upper well behaved independently. Similarly, in Figure 10e, the initial reservoir pressure of the Upper well matched its expected virgin reservoir pressure, but the Middle and Lower wells were far below their virgin reservoir pressures. From this evidence, one can conclude that the Middle and Lower benches were interfering with one another, but the Upper bench was not.

The lack of interference in the Upper bench well appears to be related to the fact that its' Young's Modulus is much higher than the Middle bench, and a barrier exists between them. On the other hand, the Middle and Lower benches share a similar Young's Moduli and no barrier appears to exist between them.

Pad 3 & 4: Intra-Bench & Inter-Bench Interference

On the western side of the same section, where elastic properties are similar to the Pad 1, wells in two more Pads (Pad 3 and Pad 4, in **grey**) were drilled in close proximity to one another (Figure 11a). The purpose of drilling wells in these pads was to test the combined effects of inter-bench and intra-bench interference.

As shown in Figure 11b, the Pad 3 and 4 wells in each bench follow a similar trend as their Pad 1 counterparts. This indicates that similar inter-bench interference is occurring between the wells in the Middle and Lower benches, but are not with the Upper bench wells. Furthermore, the degradation of performance observed in all Pad 3 and 4 wells in comparison to the Pad 1 wells indicate that the close spacing of the two pads has resulted in intra-bench interference.

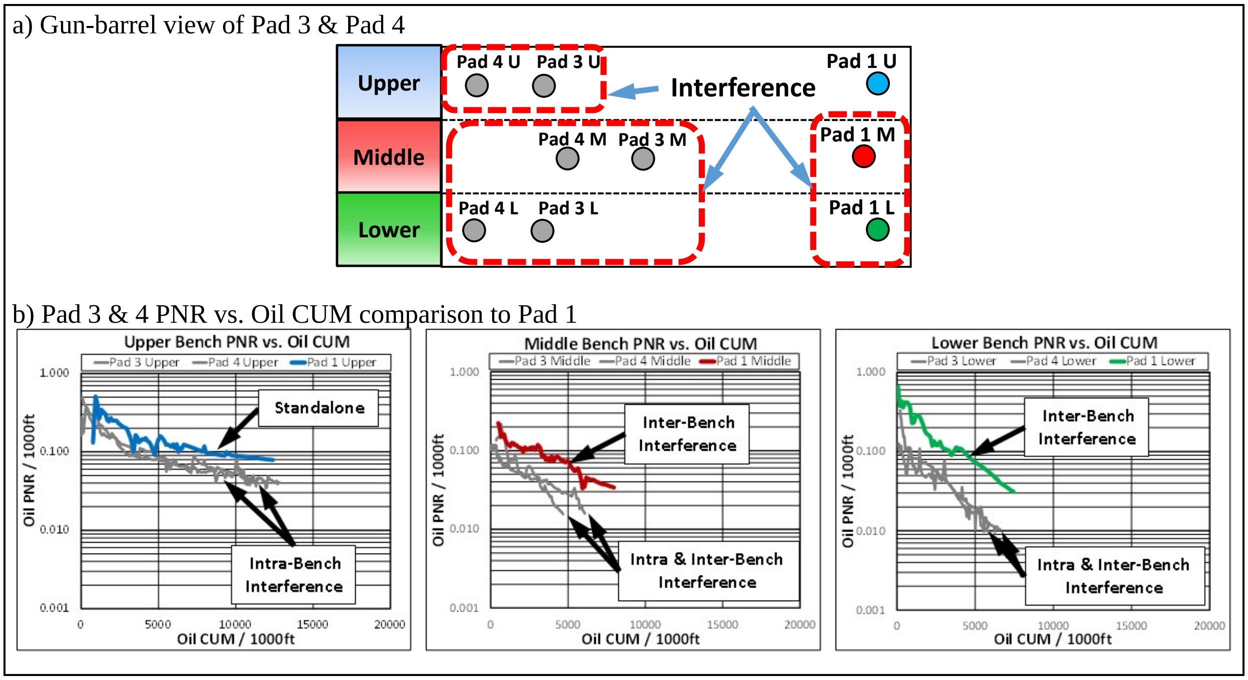


Figure 11: a) Gun-barrel view of Pad 3 and 4. b) Pad 3 & 4 versus Pad 1 Pressure Normalized Rate (PNR) vs. Cumulative Oil normalized to 1000ft of lateral length.

Pad 1, 3 & 4: Flow Barrier between the Upper and Middle benches

The question still remains on whether the lack of interference between the Upper bench wells and the Middle and Lower bench wells was due to frac barriers that arrested hydraulic fracture height growth into the adjacent benches, or flow barriers that prevented proppant transport into the adjacent benches, and limited the production of original reservoir fluids from there.

To answer this question, the extent of hydraulic fracture propagations were measured using the frac hit data and microseismic events from the Pad 3 and Pad 4 wells. As shown in the microseismic event display during the completion of the Pad 3 Upper well (Figure 12b), the hydraulic fractures appear to have propagated down to the Middle and Lower benches. Similarly, in Figure 12c, the frac treating pressures used in stimulating the Upper, Middle, and Lower benches were observed instantaneously in the shut-in wells in Pad 3 Upper and Pad 3 Middle.

These frac hits show that there are no frac barriers between the three benches, and fractures originating from any one of the three benches propagate to the other two. Therefore, the lack of inter-bench interference in the Upper bench appears to be due to a flow barrier created by a large contrast in Young's Moduli.

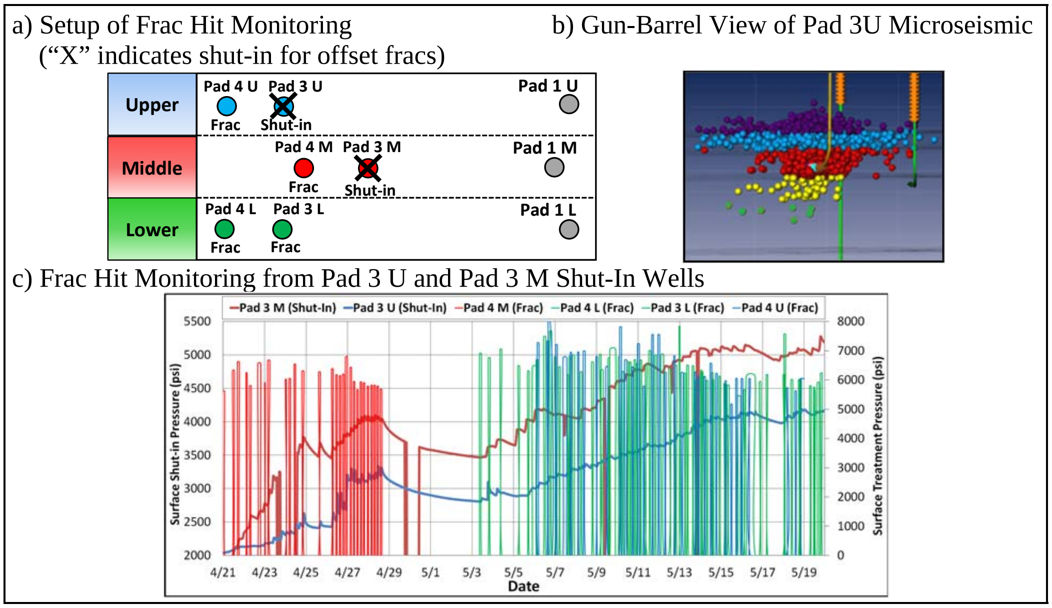


Figure 12: a) Frac-hit monitoring set-up in Pad 3 and 4. b) Microseismic of Pad 3 Upper. Microseismic events were observed in Middle and Lower benches. c) Frac hits monitored from shut-in wells, and average treating pressure of fracture stimulations. Frac hits from Upper, Middle, and Lower benches were observed in both Upper and Middle benches.

Pad 2: Inter-Bench Interference between Upper, Middle, and Lower Benches.

Wells in Pad 2 were drilled 3 miles to the west of Pad 1, where the Young's Modulus of the Middle and Lower benches are more similar to that in the Upper bench. As shown in Figure 13b, the Young's Modulus of the all three benches are approximately 6.0 MMpsi in the vicinity of Pad 2. All other geologic parameters, such as the OOIP and PVT properties, are similar to those in the area of Pad 1.

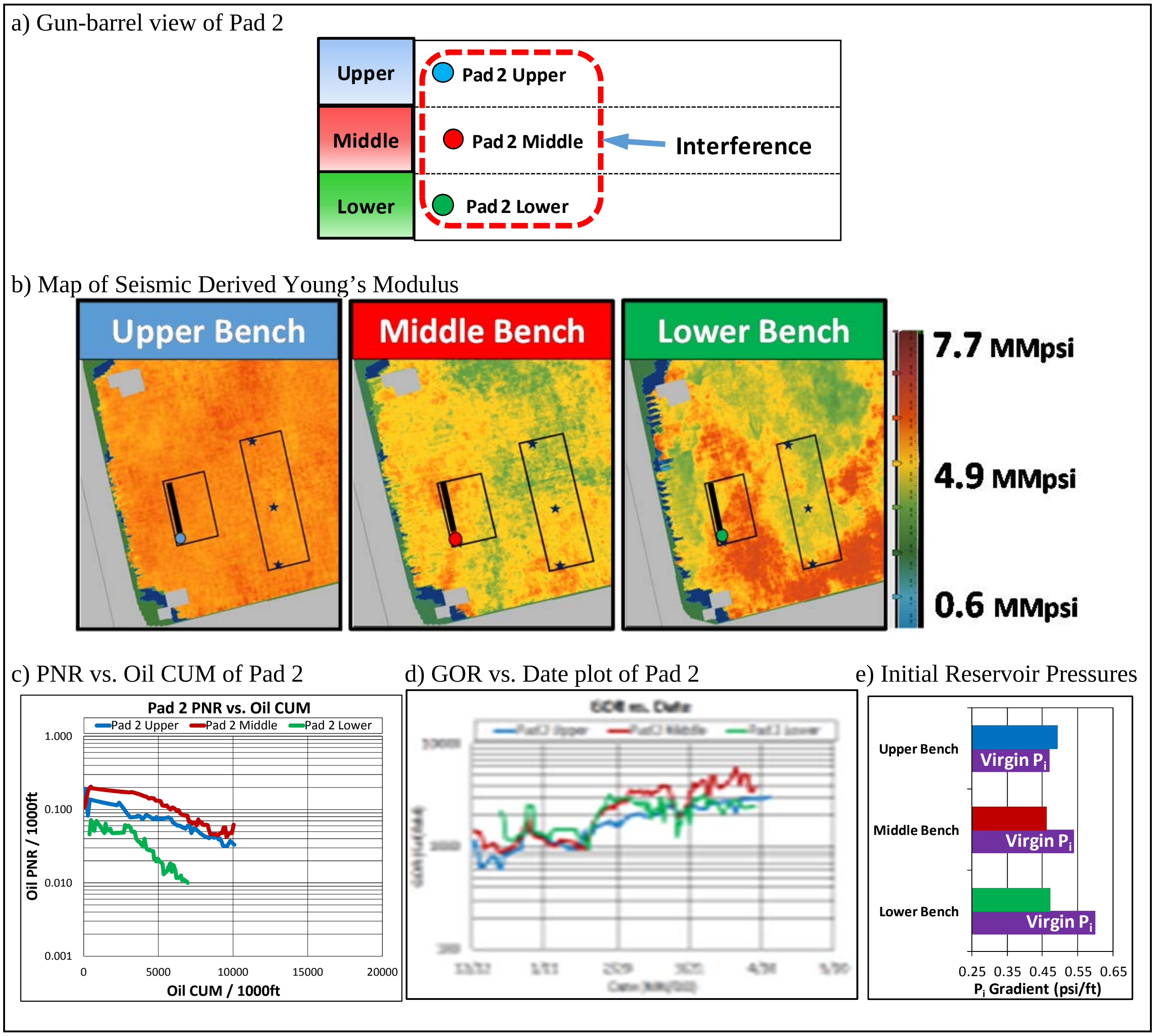


Figure 13: a) Gun-barrel view of Pad 2. b) Map of seismic inversion derived Young's Modulus. c) Pad 2 Pressure Normalized Rate (PNR) vs. Cumulative Oil normalized to 1000ft of lateral length. d) GOR vs. Date for Pad 2 wells. Upper, Middle, and Lower bench wells are interfering and have synchronized GOR trends. e) Initial Reservoir Pressures of Pad 2 wells. Upper, Middle and Lower bench wells are interfering, with the Upper bench showing a higher intial reservoir pressure than expected, and the Middle and Lower wells showing lower than expected initial reservoir pressures

As shown in the PNR analysis (Figure 13c), the Middle well outperformed the Upper and Lower wells. This is a different behavior than the Pad 1 wells, where the Upper well outperformed due to the lack of inter-bench interference. It appeared that in Pad 2, the Middle well was taking production away from the Upper well, indicating that a flow barrier does not exist between the Upper and Middle benches.

Analysis of the GOR trends and the initial reservoir pressures also show a different behavior than the Pad 1 wells. As shown in Figure 13d, the GOR trends of all Pad 2 wells were synchronized, with the first GOR rise occurring on nearly the same day. Also, the initial reservoir pressures of all three wells deviated from their respective virgin reservoir pressures (Figure 13d). The initial reservoir pressures in the Pad 2 Middle and Lower wells were below their respective virgin reservoir pressures. On the other hand, the initial reservoir pressure of the Pad 2 Upper well was higher than its virgin reservoir pressure because it was seeing the higher pressure of the Middle bench. Paradoxically, despite having a higher initial reservoir pressure than in the Pad 1 Upper bench, the first GOR rise in the Pad 2 well occurred quicker.

All of the evidence above indicates that in Pad 2, the Upper bench well interferes with the wells in the Middle and Lower benches, and no flow barrier exists between them. This corresponds to the fact that the Young's Modulus of all three benches are similar.

A shut-in test was performed in Pad 2 to confirm the inter-bench interference. As shown in Figure 14a, the Pad 2 Middle bench well was shut-in while the wells in the Pad 2 Upper and Pad 2 Lower benches continued to produce. BHP gauges were installed in each well to accurately monitor the changes in pressures.

As shown in Figure 14 b, once the Pad 2 Middle was shut-in, the P_{wf} of the Pad 2 Upper began to increase, despite the fact that it was producing. Also, when mini shut-ins were performed on the Pad 2 Lower, immediate increase in P_{wf} was observed in the Pad 2 Middle. These shut-in tests confirm the results of the integrated production analysis. Due to the similarity in Young's Moduli, there is no flow barrier between the three benches.

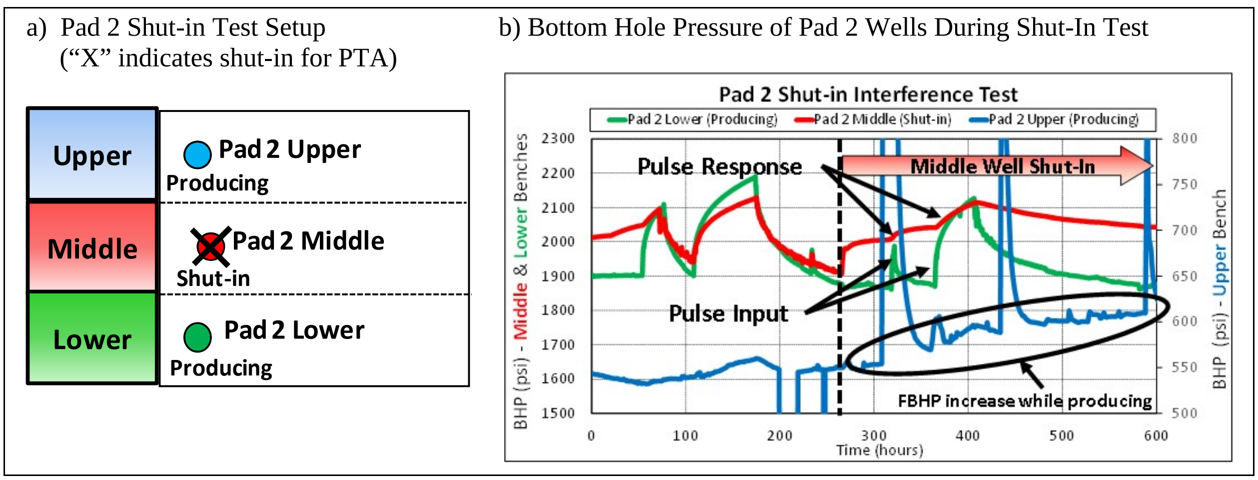


Figure 14: a) Pad 2 shut-in test setup. b) Bottom-hole-pressure of Pad 2 wells during shut-in test

Application

Since the wells in the Middle and Lower benches consistently exhibited strong interference, it was decided to test if both benches could be drained with one well. Therefore, one well was drilled in Pad 5, where Young's Moduli are similar in the Middle and Lower benches (Figure 15a). Though the Young's Modulus of the Upper bench is also similar, frac models indicated that it was beyond the limit of proppant transport and a separate well would be needed to drain it. One horizontal well was drilled in the Lower bench and a similar frac design as the other Lower bench wells was pumped to minimize the number of variables.

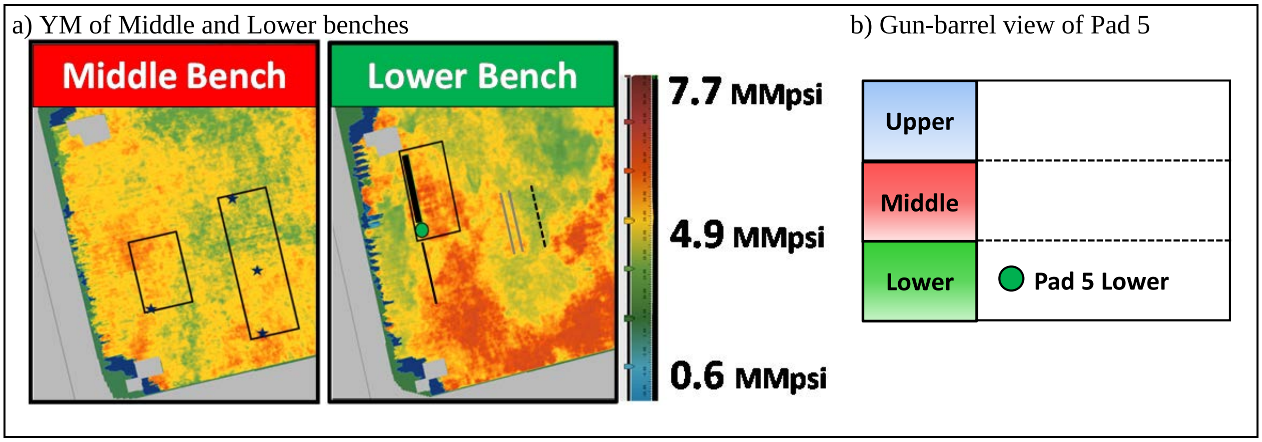


Figure 15: a) Young's Modulus of Middle and Lower benches. b) Gun-barrel view of Pad 3

The Pad 5 Lower well showed a much shallower PNR decline than other Lower bench wells (Figure 16a). This indicates that the well was draining a much larger reservoir volume and the Estimated Ultimate Recovery (EUR) would be substantially higher. Since the well was somewhat deeper, the initial reservoir pressure of the Pad 5 Lower well was slightly higher than the expected virgin reservoir pressure estimated from the eastern part of the field (Figure 16b). Lastly, the analysis of the GOR behavior confirms the observation that the Pad 5 Lower well is indeed draining a larger volume. The first GOR rise occurred much later than it did in the other Lower bench wells and the GOR appeared to stabilize at a lower value (Figure 16c).

It was also noted that the order of first GOR rise and the magnitude of the stabilized GOR were in the following order.

1. Wells affected by inter-bench and intra-bench interference (Pad 3 & 4)
2. Wells affected by inter-bench interference only (Pad 1 & 2)
3. Standalone well (Pad 5)

This shows that the more interference a well sees, the smaller the drainage volume becomes. Therefore, the GOR rises more quickly, and stabilizes at a higher value.

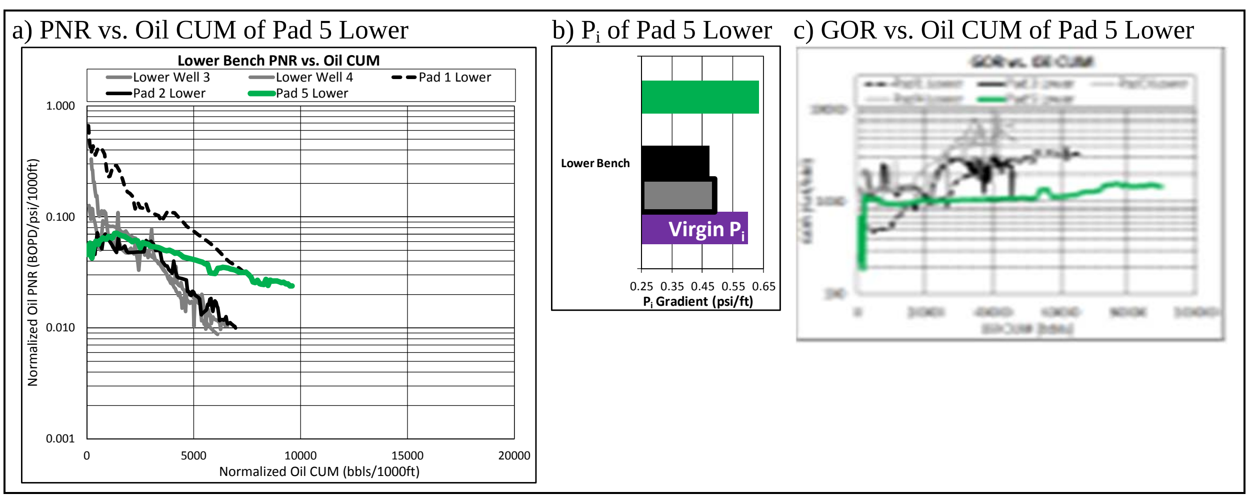


Figure 16: a) PNR vs. Cumulative Oil of Pad 5 Lower, normalized to 1000ft of lateral length. b) Initial reservoir pressure of Pad 5 Lower. c) GOR behavior of Pad 5 Lower in comparison with other Lower bench wells

The only difference between the Pad 5 Lower well versus the Pad 1 and Pad 2 wells in the Lower bench is that there was no Middle bench well directly above the Pad 5 Lower bench well. Therefore, the increased productivity must be due to the fact that the Pad 5 Lower well is draining both Lower and Middle benches. This confirms the theory that stacked benches with similar elastic properties can be drained with a single well, as long as there is no frac barrier and it is within the limitations of proppant transport.

Discussion

In this paper, an integrated analysis of production data and geomechanics for stacked bench wells was presented. Each analysis provides a different perspective on well behavior and their interactions. A fuller understanding of stacked-bench well interactions is gained by integrating these analyses

This method can be used to detect and even predict inter-bench and intra-bench interference. A large contrast in the elastic properties between stacked benches appeared to have created a barrier to the flow of reservoir fluids and wells did not communicate across benches. The contrast in elastic properties was, however, not a barrier to hydraulic fracture propagation, since frac hits and microseismic events were observed across benches. Conversely, where the elastic properties were similar between stacked benches, no flow barrier was created, and strong interference was observed. Therefore, if the elastic properties of stacked benches are similar, it is possible to drain them with a single horizontal well.

These findings agree with the experiments and models reviewed in the theory section. When a large contrast exists between stacked formations, proppant transport can be obstructed, either due to the narrowness of the fracture width (Smith et al., 2001) or the tortuosity of fracture caused by jogs and offsets at the interface (Warpinski et al., 1981, 1987; Thiercelen et al., 1987; Barree et al., 1998; Zhang et al., 2007)

Lastly, using the seismic inversion derived Young's Modulus, such flow barriers can be identified in advance. Therefore, inter-bench well spacing can be planned without an excessive number of costly trials. Once the inter-bench interaction is established, intra-bench spacing can be determined with controlled spacing trials.

Optimal well spacing is, by nature, an economic matter, that depends heavily on product prices. To adapt swiftly in a volatile price environment, geologic variables affecting well interference in stacked bench plays should be well understood.

Conclusions

1. Inter-bench well interference between stacked benches is strongly influenced by the similarity/contrast of the elastic properties of the benches. In cases where the elastic properties are similar, strong well interference can occur. In such cases, it is possible to drain multiple stratigraphic benches with a single well. On the other hand, dissimilar elastic properties between stacked benches appears to create a barrier to the flow of reservoir fluids, but not to the hydraulic fracture propagation.
2. When mechanical stratigraphy (elastic modulus) is considered, unconventional reservoirs are more heterogeneous than it appears. Seismic inversion can help understand the heterogeneity in mechanical stratigraphy.
3. Lateral intra-bench and vertical inter-bench well interference can be detected with a combined analysis of PNR, early time GOR behavior, and initial reservoir pressure estimations, without performing shut-in tests. In particular, the “GOR vs. Date” plot is useful for detecting inter-bench interference.
4. Over-capitalization of stacked bench development can be avoided using the methods outlined in this paper. Also, drilling a small number of test pads to confirm the inter-bench and intra-bench interference can save time and capital.

Nomenclature

E_{dyn} = Dynamic Young’s Modulus (psi)
EUR = Estimated Ultimate Recovery (bbls)
P_b = Bubble point pressure (psi)
P_i = Initial reservoir pressure (psi)
P_{wf} = Bottom Hole Pressure (psi)
PNR = Pressure Normalized Rate (bbls/psi)
PVT = Pressure-Volume-Temperature
q_{oil} = Oil rate (bbl/day)
R_{si} = Initial Solution Gas-to-Oil Ratio (Scf/bbl)

SRV = Stimulated Rock Volume
V_P = Velocity of compressional waves (ft/sec)
V_S= Velocity of shear waves (ft/sec)
ν_{dyn} = Poisson's Ratio (unitless)
ρ = Density (kg/cc)

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BUSINESS

Shares in Top Shale Driller Fall After it Discloses Well Problems

Concho Resources reported wells packed too closely together hurt output, a growing concern in industry

A drilling rig in Midland County, Texas.

PHOTO: JAMES DURBIN/ASSOCIATED PRESS

By Rebecca Elliott

Updated Aug. 1, 2019 4:29 pm ET

Concho Resources Inc. disclosed disappointing output from wells drilled close together, an emerging problem in the shale drilling industry, and its shares fell 22% on Thursday.

The company, one of the largest shale drillers in America's hottest oil field, the Permian Basin of Texas and New Mexico, forecast that its production would likely decline in the third quarter, due in part to an experiment to pack wells closely together that wound up hurting output.

That, along with lower natural gas and natural gas-liquids prices, led the company to scale back this year's drilling plans to stay within budget.

"We made the decision to adjust our drilling and completion schedule in the second half of the year to slow down and not chase incremental production at the expense of capital discipline," Chief Executive Tim Leach told investors.

Another factor likely weighing on Concho's shares was a decline in the price of oil, which was down Thursday morning and fell further after President Trump announced a 10% tariff on some Chinese goods.

The Midland, Texas-based driller is one of several shale companies grappling with lower-than-expected output from wells it drilled too densely. Many shale companies sought to boost production by placing wells in proximity, but have since found that doing so often means the wells produce less as they draw down the same resource, as The Wall Street Journal reported in March.

These production challenges have come into focus as investors put intense pressure on companies to live within their means after years of struggling to make money.

Concho pointed to lackluster results from a 23-well development in the western portion of the Permian, where it tried cutting the distance between its wells by 50%.

"While initial rates were solid, current performance data indicates that we developed the Upper Wolfcamp too densely," Mr. Leach said, referring to a rock formation in the Permian. "We're incorporating the data into our development model to adjust spacing on future projects."

Other tightly spaced developments are set to begin producing later this year, the company said, but they are less dense than the 23-well project.

Concho is planning to bring fewer wells to production in the second half of the year, which will translate into reduced output. The company forecast third-quarter production of 316,000 to 322,000 barrels of oil and gas a day, down from 328,681 barrels a day in the second quarter. That translates into about 201,000 barrels of oil a day, according to company forecasts, down from 205,780 barrels a day during the second quarter.

“The magnitude of the miss will invariably raise capital efficiency concerns,” JPMorgan analysts wrote in a note.

Concho reported a second-quarter loss of $97 million, down from $137 million in profit during the same period a year earlier and missing analyst expectations of profit totaling $142.6 million, according to FactSet.

That was due in part to low natural gas prices, which have weighed on shale drillers as they have struggled to get their gas to market due to insufficient pipeline and processing capacity. The company fetched an average of $1.16 per thousand cubic feet of gas, compared with $3.19 during the second quarter of 2018.

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